Draft greenfields guideline for natural gas transmission pipelines

A guide to the access regulation framework and options for new natural gas transmission pipeline developments in Australia

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1. Summary

The Australian Competition and Consumer Commission recognises that prospective investors in new pipelines need to understand how the regulatory regime will apply to their investment. It has drafted this guideline showing the alternatives available under the regulatory frameworks provided by the National Third Party Access Code for Natural Gas Pipeline Systems (the code) and Part IIIA of the *Trade Practices Act 1974* (TPA).

In light of the circumstances faced by prospective service providers when considering the construction of a greenfields pipeline, the ACCC has prepared this draft guideline to:

- address perceptions of regulatory risk with regard to the application of the regulatory framework and the ACCC's approach to the regulation of greenfields projects
- demonstrate the flexibility of the regulatory framework and the various approaches available for the structure of an access arrangement or access undertaking
- indicate the ACCC's preferred methods for dealing with project specific risks
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

For the purposes of this guideline, greenfields natural gas transmission pipeline investments are considered to be new natural gas transmission pipeline projects, the demand for the output of which was previously non-existent. These gas projects are generally acknowledged to face greater uncertainties than established investments.

In preparing this guideline the ACCC consulted with all sections of the gas industry and sought the expert views of consultants. The major findings of the consultancies have confirmed:

- the role of foundation contracts in underpinning new investment, including sharing the long-term investment risks between the pipeliner and users
- debt providers' information requirements, to assess all the risks associated with a project. This enables the debt provider to assess the risk profile of the project and determine the amount, and cost, of debt that can be made available to the pipeline developer. Equity providers similarly assess the risk profile of the project to determine their capital contribution, its structure and their required rate of return
- that the capital asset pricing model (CAPM) approach to determining the weighted average cost of capital (WACC) is an appropriate framework and specific (i.e. non-systematic) risks associated with a greenfields pipeline should not lead to an adjustment of beta—which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant biases
- project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost.

The ACCC acknowledges these findings. Accordingly, this guideline seeks to address these findings in the context of identifying the various risk categories a greenfields pipeline project is likely to face, and also to provide guidance on how the provisions of the existing regulatory framework can help a prospective investor address and mitigate relevant risks. These include:

- initial capital base of new pipelines, under the code, must be based on actual cost

- the role of foundation contracts and the preservation of contracts in existence before and subsequent to an access regime
- incentives with respect to demand forecasting and linkages with benefit-sharing thresholds. This facilitates pipeliner certainty in that there will be no intra-period re-assessment of forecasts while retaining the option to unilaterally seek a review at any time of an access arrangement in the event that its circumstances materially change
- derivation of reference tariffs is based on forecast volumes, hence the pipeliner is insulated from volume risks (with respect to cost recovery) and incentives for building spare capacity
- competitive tender processes as a means for determining reference tariffs
- benefit sharing mechanisms—which would provide the service provider with certainty from the outset—regarding the nature and effect of any benefit sharing and at what point it will commence
- term of the regulatory period is not mandated (though subject to regulatory consideration)
- CPI-X incentive mechanisms also alleviate a pipeliner's inflation risk
- depreciation schedules—being the mechanism by which pipeline investors recover the costs of an investment—can be adopted to best meet the service provider's objectives of optimising the use of its pipeline, subject to the requirement that a regulated asset is fully depreciated once, and only once, over its economic life. For example, economic depreciation effectively allows for the carry forward of losses in the early years of operation
- fixed principles, which provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods.

Background to industry development and regulation

Despite some criticism of the code it is useful to note that it was designed—with industry input—to facilitate a fair degree of flexibility for service providers in formulating an access arrangement for regulatory consideration. This flexibility provides a range of options for prospective service providers to deal with the unique risks associated with greenfields investments. Comprehensive examples are included in the appendixes to this guideline that illustrate how the aforementioned provisions might be applied in practice by a prospective service provider. It should be noted that these examples are not intended to be exhaustive and, subject to meeting the requirements of the regulatory framework, project proponents are encouraged to develop variants or alternatives that best meet their unique circumstances.

A significant level of investment has been undertaken in gas infrastructure since the gas code was introduced and further investments are currently proposed. Since 1995 more than $1 billion has been invested in upstream, transmission and distribution assets each year. Moreover, according to the Australian Pipeline Industry Association, total transmission pipeline infrastructure has grown from 9000 kilometres in 1989 to over 17 000 kilometres in 2001.[1] The AGA notes that it expects average annual growth in demand for gas to be 4.3 per cent until 2014–15. Gas is currently 17.7 per cent of the total energy supplied in Australia. The Australian Gas Association (AGA) expects this to grow to 22 per cent by 2005 and to 28 per cent by 2014–15.[2]

However, despite the substantial investment in new infrastructure in the energy sectors, concerns have been raised about whether the relevant codes can adequately address the specific needs of a greenfields investment. Accordingly, the ACCC is conscious of the need to:

- balance the interests of users and investors
- provide incentives for long-term efficient investment

1 Australian Pipeline Industry Association, *Business Plan 2002–2005*.

2 Australian Gas Association, Gas Industry Development Strategy 2000–2015.

- set prices that track efficient costs as closely as possible.

In making regulatory decisions the ACCC must establish an appropriate rate of return. In doing so, balance must be achieved between the needs of service providers and users. The perceived short term gains of reducing prices for infrastructure services must be balanced with the ongoing viability of the business and the industry as a whole. This includes assessing access proposals (and not just a rate of return) for a business that will provide the appropriate incentives, and accommodate new efficient investment in infrastructure. Only then will long-term efficiencies arise and benefit the economy.

The ACCC's perception is that the code offers a degree of flexibility that is yet to be fully realised by the pipeline industry. The ACCC also regards access undertakings under Part IIIA as containing a significant level of flexibility. Regulation under Part IIIA may be regarded by service providers as an alternative to regulation under the code. The ACCC's current guide to Part IIIA outlines the provisions and requirements of the Trade Practices Act.

While prescribing a range of matters that the regulator is required to consider, the gas code also provides a number of provisions and options for prospective regulated greenfields pipelines that can address any uncertainty regarding the application of the regulatory regime. The onus is on the prospective service provider to submit an access arrangement to the ACCC for assessment that complies with the objectives of the gas code.

The gas code recognises that to encourage investment, a prospective service provider should be given the opportunity to reap some of the returns that exceed the expected level where those returns are attributable to the efforts of the service provider. Often referred to as the 'blue sky' potential of the pipeline such an approach requires regulatory certainty about the treatment of any greater than normal returns, if realised, in the initial regulatory period/s. The inclusion of an incentive mechanism in an access arrangement (or access undertaking) is an important component of a service provider's regulatory framework. The ACCC encourages service providers to develop mechanisms that will best suit their particular needs.

Without constraining the intentions of the gas code in this regard, the challenge for regulators is to assess access regime proposals to ensure that they establish fair and reasonable conditions of access for both service providers and users in a manner that preserves the service provider's economic incentives to fully utilise its assets and develop its business. The access regime must also ensure the abuse of monopoly power is prevented.

It is intended that this guideline will therefore help achieve greater certainty through greater transparency and resolve some of the reasonable concerns that have been raised about the difficulties of developing new pipelines.

Finally, it is important to note that regulation of gas transmission infrastructure in Australia is not presumed as a necessary condition precedent for the effective functioning and development of natural gas markets in Australia. A number of tests must be satisfied before a pipeline, or prospective pipeline, is subject to the requirements of the regulatory framework. Accordingly, the ACCC is only concerned with the regulation of natural gas transmission pipelines that either meet the coverage tests under the gas code or are subject to an access undertaking or declaration under Part IIIA of the Trade Practices Act.

In Australia the National Competition Council is responsible for making coverage and declaration recommendations.

Nevertheless, some service providers may perceive benefits in securing certainty about the application of the regulatory framework to their particular assets at the outset.

2. Introduction

Despite the substantial investment in new infrastructure in the energy sectors, concerns have been raised about whether the regulatory framework can adequately address the specific needs of a greenfields investment. The ACCC is conscious of the need to:

- balance the interests of users and investors
- provide incentives for long-term efficient investment
- set prices that track efficient costs as closely as possible.

The ACCC recognises that prospective investors in new pipelines need to understand how the regulatory regime will apply to their investment. The ACCC has drafted this guideline to show what alternatives are available under the regulatory frameworks of the National Third Party Access Code for Natural Gas Pipeline Systems and Part IIIA of the Trade Practices Act 1974.

The intention of this guideline is to help achieve greater certainty through greater transparency and to resolve some of the concerns that have been raised about the difficulties of developing new pipelines.

While each pipeline throughout Australia is likely to face unique and differing levels of risk, greenfields pipeline[3] projects are generally acknowledged to face greater uncertainties than established pipelines. For example, a new pipeline without significant foundation contracts proposing to supply gas to a new or immature market, faces greater uncertainty regarding future demand than a 20-year-old pipeline that is fully contracted and supplying to a well established customer base. The growth in future demand for a new pipeline can often be dependent upon a number of factors, including other new projects securing funding and remaining operational (e.g. a fertiliser production plant or a gas fired generator) and/ or the rate at which users convert from other fuels to natural gas.

In light of the circumstances faced by prospective service providers when considering the construction of a greenfields pipeline, the ACCC has produced this guideline to:

- address perceptions of regulatory risk with regard to the application of the regulatory framework and the ACCC's approach to the regulation of greenfields projects
- demonstrate the flexibility of the regulatory framework[4] and the various approaches available for the structure of an access arrangement or access undertaking
- indicate the ACCC's preferred methods for dealing with project-specific risks
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

This guideline outlines the flexibility available to a prospective service provider when considering the submission of either an access undertaking or an access arrangement. This guideline is not intended to be exhaustive and the ACCC is receptive to considering alternative methods, provided that any proposed approach is consistent with the principles of the National Third Party Access Code for Natural Gas Transmission Pipelines or, in the case of an access undertaking, Part IIIA of the Trade Practices Act.

[3] For the purposes of this guideline, a greenfields pipeline is generally considered to be a new natural gas transmission pipeline project, the demand for the output of which was previously non-existent.

[4] The regulatory framework for natural gas transmission pipelines in Australia is comprised of the National Third Party Access Code for Natural Gas Transmission Pipelines and Part IIIA of the *Trade Practices Act 1974*.

In preparing this guideline the ACCC consulted with industry, which included hosting a roundtable discussion in November 2001 with representatives from all sections of the gas industry and regulatory staff. Following the input received from the roundtable discussions the ACCC sought the expert views of:

- Macquarie Bank, on the issues relevant to debt and equity providers[5]
- Messrs Kevin Davis and John Handley, on the appropriate cost of capital
- National Economic Research Associates, on the role of foundation contracts and related terms and conditions relevant to greenfields natural gas pipeline projects.

The key findings of these consultancies are summarised in appendix 5. Copies of the consultancies are also available at the ACCC's website.[6]

Prospective service providers are encouraged to consult with the ACCC when developing an access proposal. However, it is ultimately the service provider's responsibility to design an access proposal that best meets its unique needs and circumstances, while complying with the principles of the national access regime. The ACCC can assist prospective service providers with a preliminary non-binding view on a proposed access arrangement or undertaking; however, for it to provide a well considered response, a sufficient amount of relevant and useful information will be necessary. Prospective service provider consultation with the ACCC is discussed in detail in section 7.

The guideline is structured as follows:

Section 1	Summary
Section 2	Introduction
Section 3	Overview of the regulatory framework and the bases for determining when a prospective pipeline is likely to be subject to regulation or can be voluntarily submitted for a regulatory determination.
Section 4	The major risk categories faced by a greenfields pipeline and considerations for mitigating those risks.
Section 5	The range of risk mitigation options available in relation to tariff setting, downside risk, the role of foundation contracts and contractual commitments and determination of the regulatory asset base.
Section 6	Managing uncertainty in relation to demand forecasting and securing the potential to reap blue-sky opportunities.
Section 7.	Discusses the provision of information and regulatory consultation considerations.
Appendix 1	Example of the derivation of expected demand and expected return forecasts when facing uncertainty.
Appendix 2	Example of an adjustment to the initial capital base to reflect actual costs and the effect/s on reference tariffs.
Appendix 3	Example of determining benefit sharing when demand exceeds a pre-set threshold and effect on revenues, profits and tariffs.
Appendix 4	Summary of the consultancies undertaken.
Appendix 5	Summary of code provisions that facilitate regulatory certainty.
Appendix 6	Glossary.
Appendix 7	Related publications.

5 The ACCC recommends that readers refer to the consultancy report, including the executive summary, for a description of the terms of reference for the report.

6 <http://www.accc.gov.au/gas>

Copies of this draft *Greenfields guideline for natural gas transmission pipelines* and related consultancies are available on the ACCC's website at: <http://www.accc.gov.au/gas>.

Following the release of the draft guideline the ACCC will hold a public forum at which interested parties can raise any issues or make comments on the guideline. Details of the public forum will be well publicised in the major daily press.

Any comments on the draft guideline should be addressed to the following email address <gas@accc.gov.au>.

Alternatively, written comments should be addressed to:

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3. The regulatory framework

Essentially, a prospective service provider has three possible alternatives regarding the regulatory environment when considering a greenfields pipeline project:

(i) the pipeline becomes ‘covered’ under the National Third Party Access Code for Natural Gas Pipeline Systems

(ii) an access undertaking in relation to the pipeline is submitted by the service provider under Part IIIA of the Trade Practices Act

(iii) the pipeline is unregulated.

Each of these alternatives is discussed further below.

A prospective service provider may choose to be regulated from the outset for a number of reasons depending on the environment and circumstances facing the pipeline. For example, a service provider may prefer certainty from the outset in relation to the application of elements of the regulatory regime or there may be strong reason to believe that coverage will be sought (and approved) on the pipeline in question.

3.1 Role of the National Competition Council

Part IIA of the Trade Practices Act sets outs the functions of the National Competition Council (NCC).[7] The NCC is an independent statutory council that has a function in recommending to the Federal Treasurer and to the responsible State and Territory Ministers the declaration of services under the essential facilities provisions of Part IIIA.

Part IIIA provides for existing access regimes, such as the code, to be recognised as ‘effective’ by the relevant Minister (on recommendation from the NCC). As at April 2002 the respective access regimes established by the code and its supporting legislation have been certified effective in South Australia, Western Australia, New South Wales, Victoria, the ACT and NT, with a decision pending on an application from Queensland.

Alternatively, in the absence of an access regime that has been certified as effective under Part IIIA any person (for example a third party who may have been unsuccessful in privately negotiating access on an unregulated pipeline) may apply to the NCC for a recommendation to the relevant Minister, that the service be ‘declared’.[8]

Additionally, under the code, the NCC has a role in making recommendations to the relevant Minister whether or not a pipeline should be ‘covered’.[9]

3.2 Coverage under the code

The code establishes a national access regime for natural gas pipelines. It sets out the rights and obligations of service providers, pipeline users and access seekers. It includes coverage rules, the operation and content of access arrangements, ring fencing arrangements, information requirements, dispute resolution and pricing principles. Under the code the ACCC is responsible for the regulation of all covered transmission pipelines in Australia, with the exception of Western Australia.[10]

7 National Competition Council website can be found at <http://www.ncc.gov.au>.

8 ACCC, Access regime—a guide to Part IIIA of the Trade Practices Act, November 1995.

9 Refer code section 1.2.

10 The Office of Gas Access Regulation (OffGAR) is the responsible regulator for transmission and distribution of natural gas pipelines in Western Australia.

Once a pipeline becomes covered it is subject to the principles set out in the code. There are three ways in which a greenfields pipeline may become covered.

- A service provider or prospective service provider can volunteer that a pipeline be subject to the provisions of the code by proposing an access arrangement to the regulator for approval. Following the regulator's approval the pipeline is covered from the date that the access arrangement becomes effective until any specified expiry date (sections 1.20 and 2.3 of the code).

- A pipeline is automatically covered if it is subject to a competitive tendering process approved by the regulator (section 1.21).

- Any person may make an application to the NCC requesting that a pipeline be covered (section 1.3). The NCC subsequently provides a recommendation to the relevant Minister, who makes a decision on the matter. The criteria for determining whether a pipeline should be covered is set out in section 1.9 of the code.

Before deciding on a regulatory approach, if any, a prospective service provider has the option to seek a (non-binding) opinion from the NCC[11] on whether a proposed pipeline would meet the criteria for coverage in section 1.9.

Flexibility of the code

The ACCC considers that the code has been drafted with the clear intention of accommodating access arrangements for prospective pipelines. This view is supported by the findings of National Economic Research Associates (NERA), its analysis is that the code serves as an effective access regime which helps, rather than hinders, the expansion of an integrated gas pipeline infrastructure in Australia.[12]

While prescribing a range of matters that the regulator is required to consider, the code provides a number of provisions and options for prospective regulated greenfields pipelines that can mitigate uncertainty regarding the application of the regulatory regime. These options, and illustrative examples, are set out in more detail in the following sections.

3.3 Submission of a Part IIIA undertaking

Part IIIA provides a legal regime to facilitate access to the services of certain facilities of national significance. Under Part IIIA, service providers can submit access undertakings to the ACCC specifying the terms on which access will be made available to third parties.

Section 44ZZA of the TPA sets out the matters the ACCC must have regard to in deciding whether to accept an undertaking:

- the legitimate business interests of the provider

- the public interest

- the interests of potential third party users

- whether there is an existing access regime

- any other matters the ACCC thinks relevant.

The open ended nature of the criteria gives the prospective service provider considerable scope to design and implement an undertaking according to its needs and gives the ACCC flexibility in analysing and assessing the undertaking. At the same time such flexibility may create uncertainty about the ACCC's approach and could lead to concerns over perceived inconsistencies between undertakings. To mitigate these concerns the ACCC has a guideline, *Access undertakings*, for the submission of an access undertaking.[13]

The undertakings guideline is structured to help prospective service providers and other interested parties understand what is involved in having an access undertaking accepted by the ACCC. It outlines:

[11] Refer code section 1.22.

[12] National Economic Research Associates, *Natural Gas Pipeline Access Regulation—Report for BHP*, 31 May 2001, p. 2.

[13] ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999.

- procedures for assessing and lodging access undertakings
- the legislative criteria for assessing undertakings and the main factors that the ACCC will take into account in applying them
- guidelines on what an owner/operator of a facility should include in an undertaking.

While the legislative criteria take precedence over the ACCC's published guidelines, the guidelines describe the ACCC's considered view on how an access undertaking should be approached. Accordingly, the ACCC, in ensuring careful consideration of the merits of an undertaking proposal, requires owners/ operators to provide sound reasoning and justification should they wish to depart from the approach foreshadowed in the guideline.

Prospective service providers considering the submission of a Part IIIA undertaking should consult the *Access undertakings* guideline in conjunction with this guideline when considering the content of an undertaking.

3.4 Similarities between regimes

While the code may appear more prescriptive than Part IIIA, both are essentially based on the same principles.

Part IIIA was the basis upon which the code was developed and the intention was that an 'access arrangement would be similar in many respects to an undertaking under Part IIIA'[14]. Further, the code was specifically designed to address access to natural gas pipelines and is a major component of access regimes that have been certified as effective in a number of jurisdictions.

Given this, it is not unreasonable that the ACCC would look to the code for guidance when assessing a proposed access undertaking. The ACCC considers that the code reflects necessary principles that are likely to be relevant to any consideration of an access undertaking. Therefore, the ACCC recommends that prospective service providers provide a sound rationale should they seek to depart from the principles contained in the code.

The *Access undertakings* guideline indicates that whatever pricing methodology is chosen, it would require reference tariffs to be 'based on the efficient costs of providing reference services' and 'prices should converge towards efficient costs over time'. In a similar vein the reference tariff principles given in section 8 of the code specify, among other things, that a reference tariff policy should be designed to 'improve efficiency and to promote efficient growth of the gas market', 'replicate the outcome of a competitive market' and 'be efficient in level and structure'.

3.4.1 Potential for regulatory overlap

Part IIIA provides for existing access regimes, such as the code, to be recognised as 'effective' by the relevant Minister (on recommendation from the NCC). The services covered by jurisdictional gas access regimes that have been recognised as 'effective' under s. 44N of the TPA can not subsequently be the subject of a declaration application to the NCC.

However Part IIIA does not explicitly state that certification of an access regime as 'effective' also excludes the operation of an undertaking. Therefore, technically, there is a possibility of regulatory overlap arising. That is, a particular pipeline could potentially be the subject of an access arrangement and an access undertaking at the same time.

In assessing undertakings the ACCC will establish whether there is an existing access regime and if so whether an undertaking is necessary.[15] Given the similarities between the regimes and additional costs of implementing two regimes simultaneously, the ACCC would be unwilling to accept an undertaking where an approved access arrangement is already in place unless there are strong reasons for doing so.

Conversely, it is possible that an application is

[14] National Third Party Access Code for Natural Gas Pipeline Systems, November 1997, p. 1.

[15] ACCC, *Access undertakings—a guide to Part IIIA of the Trade Practices Act*, September 1999, pp. 15, 16.

made to the NCC for coverage of a pipeline that already has an existing access undertaking in place. In its assessment of the application for coverage of the Eastern Gas Pipeline (EGP), the NCC indicated that the presence of an access undertaking should be taken into consideration when assessing the potential benefits of coverage under the code. At the time Duke Energy International had lodged a draft undertaking for the EGP with the ACCC for assessment. As the ACCC had not made a decision regarding the undertaking it was difficult for the NCC to place much weight on the undertaking.[16] However, the NCC has indicated that if an approved access undertaking is in place, it is unlikely that a recommendation for coverage will be made.

Section 1.9(a) of the code requires the NCC (and decision-maker) to be satisfied that competition would be promoted in a dependent market by regulation under the code. This is to be compared with the likely state of competition without regulation under the code (EGP decision). If the pipeline is regulated by an undertaking, it is unlikely that regulation under the code would promote competition, so criterion (a) will not be met.

This interpretation of section 1.9(a) of the code is further supported by a recent decision of the designated Minister to accept the recommendation of the NCC and not declare the rail network services provided by Freight Australia which were the subject of an application for declaration. The basis for this decision was that declaration would not have promoted competition given that access was already provided under the Victorian access regime.[17] Accordingly s. 44H(4)(a) of the TPA was not met. Section 1.9(a) of the code is essentially the same as s. 44H(4)(a).

A prospective service provider may request an opinion from the NCC on whether a proposed pipeline would meet the criteria for coverage in section 1.9.[18] Prospective service providers considering an access undertaking are also encouraged to consult with the ACCC in advance of lodgment.[19]

3.5 Unregulated pipelines

A prospective service provider also has the option to elect, on the basis of its own commercial judgment, with or without consultation with regulatory authorities, to build an unregulated greenfields pipeline. For example, a prospective service provider may be of the view that the pipeline would be too small to meet the tests under Part IIIA or the code, or that the costs of imposing regulation would outweigh the benefits.

It is important to note that a service provider's election not to provide a voluntary access regime does not preclude access being sought by some other party in the future. As noted earlier, under the code any person may at any time make an application to the NCC requesting that a pipeline be covered. If, based on the NCC recommendation, the relevant Minister decides that the pipeline should be covered, the service provider would then be required to submit an access arrangement for the pipeline. Therefore, while a prospective service provider may consider regulation of a pipeline inappropriate or unnecessary, it is possible that coverage of the pipeline may be sought some time in the future by a third party.

In the absence of an access regime that has been certified as effective under Part IIIA any person (for example a third party who may have been unsuccessful in privately negotiating access on an unregulated pipeline) may apply to the NCC for a recommendation to the relevant minister, that the service be declared.[20] If successful the terms and conditions of access to a declared service are to be negotiated by the parties in the first instance, with the ACCC being empowered to arbitrate access disputes notified to it, having regard to the arbitration criteria specified in the TPA.[21]

16 NCC, Final recommendation—Application for coverage of Eastern Gas Pipeline, p. 17.

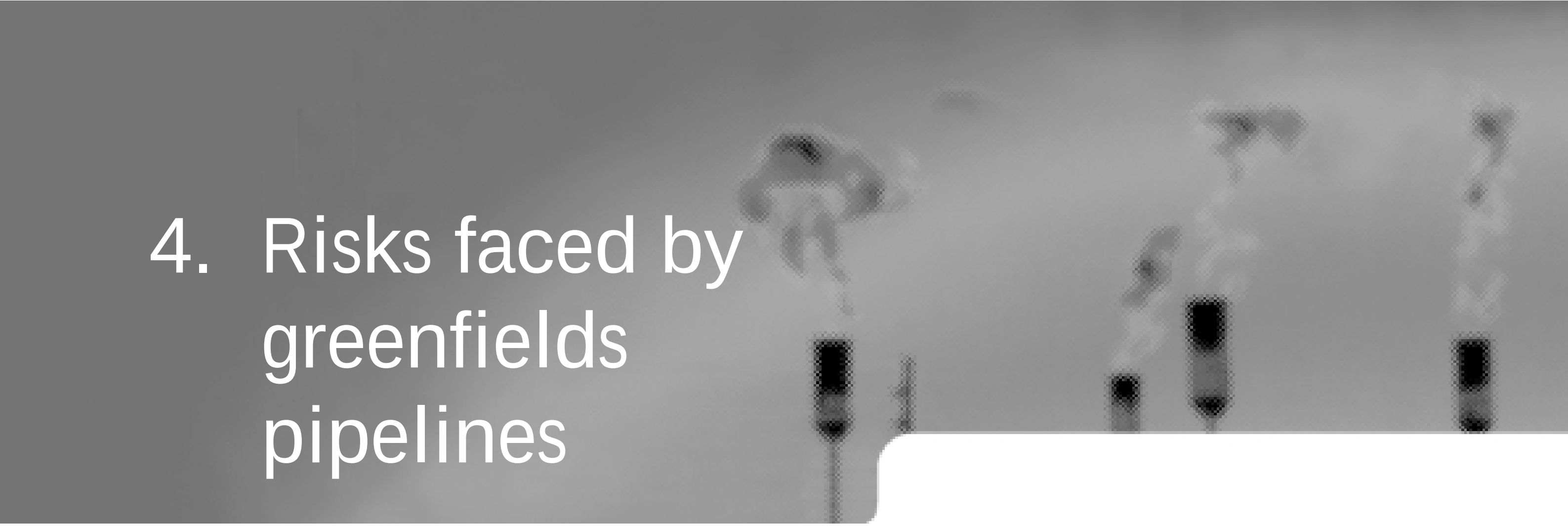
17 I Campbell (Parliamentary Secretary to the Treasurer), Statement of decision and reasons concerning the application for declaration of rail network services provided by Freight Australia, 1 February 2002.

18 Refer code section 1.22

19 ACCC, *Access undertakings—a guide to Part IIIA of the Trade Practices Act*, September 1999, p. 64.

20 ACCC, *Access regime—a guide to Part IIIA of the Trade Practices Act*, November 1995.

21 ibid.



4. Risks faced by greenfields pipelines

The ACCC acknowledges that prospective greenfields pipeline investors may face a different risk profile to an incumbent pipeline operator. Although some risks may not necessarily be unique to the prospective service provider, the overall level of project risk may be greater for a greenfields pipeline project than it is for an established pipeline serving established customers.

Clearly there is a myriad of individual risk elements that require identification and management in any greenfields pipeline proposal. However, it is recognised that, in general terms, greenfields pipelines face the following broad risk categories during the planning, construction and operational phases of a pipeline's life.

(a) Financing phase e.g.:

- procuring materials that might be sourced in foreign currency, noting such financial risks may occur in either, or both, the construction and operational phases of greenfields pipeline projects.

(b) Construction and completion phases in the development of a greenfields pipeline e.g.:

- completion delay because of weather or other factors, significant cost over/under-runs, timing requirements that may necessitate a greenfields pipeline committing substantial capital well ahead of final approvals.

(c) Operational phase e.g.:

- unexpected failure and maintenance resulting from a hostile environment and loss of transportation tariff revenue.

(d) Demand forecasting e.g.:

- the uncertainties associated with forecasting demand volumes, likely market growth factors and realisable revenues etc.

With respect to a proposed pipeline, it is recognised that the aggregate potential effects of such project risks need to be considered in any greenfields pipeline evaluation, both for the purposes of the greenfields pipeline assessment of whether or not to proceed with an investment, and for the purposes of determining reference tariffs. In addressing risk it is important to note the different contexts in which the term is used. Namely systematic risk which is compensated for in the capital asset pricing model (CAPM) in the regulatory framework, as compared to the more generic concept of referring to the possibility of an adverse event.

4.1 The treatment of risk in the regulatory framework

Whether assessing an access proposal under the code or Part IIIA, the ACCC is required to make a determination that balances the legitimate interests of the service provider, existing users, potential third party access seekers and the broader public interest. The legitimate interests of the service provider include providing a rate of return that is commensurate with prevailing conditions in the market for funds and with the commercial risk associated with providing the reference service.

Notwithstanding the development risks a greenfields proponent faces (which are addressed below), it is well established in the finance literature that the appropriate measure of risk for determining the rate of return on a project (whether greenfields or mature) is the systematic risk of a project and not its total risk.[22]

As noted by NERA[23], this approach is consistent with that adopted by the Federal Energy Regulatory Commission (FERC) in the US whereby no additional allowance is made in setting the allowed rate of return for the 'risk' a pipeline service provider faces in needing to fill capacity or sign long-term contracts.

To the extent that it may occur in regulated transmission pipelines, 'asymmetric risk', which is where either the downside risk or the upside risk dominates; over time resulting in a net cost or a net benefit respectively, can be addressed in the regulatory framework. Clearly asymmetric risk does not solely affect either service providers or users but depends on the nature of the risk categories being considered.

Risk can be divided into two categories: systematic (non-diversifiable), and non-systematic (diversifiable) risk. Systematic risks are the market-related risks faced by an investor irrespective of the industry. Examples are the risk of political upheavals and economic up-turn or down-turn.

Compensation for systematic risk is made though the market-risk premium and beta factors found in the Capital Asset Pricing Model (CAPM). The CAPM requires compensation for systematic risk only, as firm-specific risk can be eliminated through diversification. The equity beta is a statistical measure that indicates the riskiness of one asset or project relative to the whole market (usually taken to be the Australian stock market). With the market average being equal to one, an equity beta of less than 1 indicates that the stock has a low systematic risk relative to the market as a whole. Conversely, an equity beta of more than one indicates that the stock has a relatively high risk.

Where an equity beta is calculated for a particular company, it only applies to the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders. Hence the equity beta will change. It is possible to derive the beta that would apply if the firm were financed with 100 per cent equity, known as the 'asset' or 'unlevered beta'. This means companies with different capital structures can be compared. The analyst can then calculate the equivalent equity beta for any level of gearing desired, known as 're-levering' the asset beta.

Non-systematic risks are specific or unique to an asset or project and may include asset stranding, bad weather and operations risk. Such risks by their nature are specific and need to be assessed separately for each access arrangement. Importantly, specific risks are independent of the market. For an investor, exposure to the specific risk related to an asset can be reduced or countered by holding a diversified portfolio of investments. Consequently, specific risk is not reflected in the equity beta parameter of the CAPM.

While other asset pricing models involving additional risk factors have been developed in the literature, the CAPM is currently still considered to be the dominant approach adopted in practice for estimating required rates of return.[24] The ACCC considers that the CAPM is an appropriate framework for assessing the WACC (weighted average cost of capital) facing a greenfields natural gas transmission pipeline. Accordingly the integrity of the CAPM model should be maintained, in that it only recognises risks of a systematic or market related nature. The ACCC will only consider variations to the CAPM that are purely of a systematic type. Specific, i.e. non-systematic, risks associated with a greenfields pipeline should not lead to an adjustment of beta—which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant bias.[25]

A matter of significant debate in the ACCC's assessment of the Victorian access arrangement was the treatment of specific (diversifiable) risk. As discussed above, the equity beta is meant to reflect only market-related or non-diversifiable risks. Consistency with the CAPM

[22] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002.

[23] National Economic Research Associates, Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios, October 2000.

[24] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002.

[25] ibid.

framework therefore requires that specific risks be factored into projected cash flows rather than the cost of capital. The ACCC indicated in its *Draft Statement of Regulatory Principles* that this is the approach the ACCC will normally adopt with respect to identified and quantified specific risks[26] and has done so in all subsequent decisions. This is consistent with the former Office of the Regulator General's (now the Victorian Essential Services Commission) assessment, as stated in its first consultation paper for the 2003 review of gas access arrangements:

> *… while events that are unique to particular businesses do not affect the cost of capital, they are not irrelevant. Rather, the price controls should be designed to ensure that the regulated entity expects to earn its costs of capital on average, taking account of all possible events.*[27]

The ACCC understands that prospective service providers will need to undertake detailed market surveys, technical and financial analysis of a range of matters in the project evaluation phase of a greenfields pipeline and that a number of parties involved in such a project will need to assess such data. For example, as noted in Standard and Poor's criteria for the project financing of pipelines[28] an in-depth analysis of the type and nature of the contracts in place between a service provider and users is required to be undertaken to assess the credit profile of a pipeline. Financiers similarly need to conduct a comprehensive due diligence of the market survey assessments and projections undertaken for a pipeline financing proposal to assess the overall risk and viability of the funding proposition sought.[29]

Regulatory decision making processes similarly need to consider such data. However, in the regulation of gas transmission pipelines the ACCC does not conduct traditional rate of return regulation. Rather, it adopts an incentive regime that encourages the regulated business to outperform the benchmarked return (as determined by the reference tariff for the 'reference service', forecast costs and forecast demand) for the regulatory period. This regime provides incentive mechanisms by encouraging service providers to reduce their costs in any given regulatory period and maximise the efficient use of the infrastructure. If the provider realises cost savings in that period, while maintaining a given level of service standards, it may be able to retain those savings. A service provider can also earn above benchmark returns by increasing its customer usage above forecast demand.

The ACCC's post tax revenue model[30] provides prospective service providers with an interactive working example that demonstrates the application of these principles to facilitate compensation for systematic risks and the relevant operations and maintenance, depreciation and net tax payable costs incurred over the regulatory periods.

4.2 Financing phase

Consistent with the benchmarking approach outlined above and with the objectives of the code and Part IIIA, the ACCC considers that when legitimate costs are incurred as a result of, or in an attempt to mitigate, financial risk then such costs can be appropriately recognised and compensated for in the regulatory regime. Clearly compensation for such costs can only apply where they are of a non-systematic nature and are not otherwise compensated for, eg where such costs are not provided for as an element of the costs to which the incentive based benchmarking approach applies.

For example, a project might procure materials from overseas and manage its financial risk through the use of appropriate hedging or swaps arrangements. If the related costs are attributable to construction related costs then such costs could be capitalised and reflected in the initial capital base (ICB) of the asset.

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26 ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999, p. 79.

27 Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No. 1,* p. 60, May 2001.

28 Standard and Poor's, Infrastructure finance—Criteria for project financing of pipelines, 2001.

29 Macquarie Bank Limited, Issues for debt and equity providers in assessing greenfields gas pipelines, May 2002.

30 ACCC, *Post-tax revenue handbook*, October 2001. This can be found on the ACCC's website at <http://www.accc.gov.au/gas/>.

Similarly, for variations in capital costs that might occur as a result of changes in the exchange rate, the code provides for the use of actual cost to value the capital base for new pipelines.

4.3 Construction phase

The ACCC recognises that in the planning and construction phases of a greenfields pipeline there is a range of risk elements common to any construction contract, irrespective of whether the construction is related to an unregulated or regulated service.

For greenfields pipelines that are to be subject to a regulatory regime, the code provides scope for insulating a prospective greenfields pipeline from construction cost risk, in that cost overruns will be included in the ICB as a component of 'actual capital cost'[31] and, subject to the provisions of section 8.9 of the code, there is no reassessment of actual cost in subsequent regulatory reviews.[32]

Similarly, Part IIIA requires the ACCC to have regard to the legitimate business interests of the service provider, which includes the ongoing viability of services covered by the undertaking and commercial returns on investment in the facility.

One of the aims of both Part IIIA and the code is to promote efficiency. Application of Part IIIA or the code does not provide for compensation to prospective service providers for any damages arising from failure, on the part of the service provider, to meet contractual obligations to its customers. Therefore, in the event that a delay is attributable to a prospective service provider this should not create the perverse situation whereby any resulting costs are ultimately passed on to users as a component of the reference tariff(s).

Accordingly, the ACCC does not consider that it is the intention of Part IIIA or the code to compensate a prospective service provider for risks that can be addressed through normal commercial practice, such as the management of construction risks via contractual or other arrangements for gain/pain sharing between owners, prime and sub-contractors. For example:

- regarding possible timing overruns, the ACCC notes that in fixed price or cost plus contracts, accepted practices provide for back to back provisions in such contractual arrangements
- alternatively, alliance-contracting principles provide a range of options and incentives for all contracting parties to best manage project risks.

For example, a prospective service provider might enter into a contractual commitment with a prospective user that incorporated penalties for failure to deliver gas by a pre-agreed date. Then, in the event of a failure to deliver by that date, it would clearly be an undesirable outcome if the regulatory framework effectively allowed the service provider to recoup those penalty payments by reflecting them in the capital base. The effect of this would be to ultimately pass those costs through to those same users.

Such contractual management arrangements in construction contracts are not an explicit component of the regulatory regime and are entirely within the remit of the prospective service provider. Further, a prospective service provider can insulate itself from claims by foundation customers by providing flexibility in foundation contracts. Where delays are not attributable to the prospective service provider, the ACCC would anticipate that a prudent service provider would seek to recover any damages arising under its contractual arrangements.

This approach is consistent with the findings of Davis and Handley who noted:[33]

> Project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost. Provided that the capital base concept adopted for use in regulatory price determination reflects the cost of such risk transfer, or that the cash

[31] Refer code section 8.12.

[32] Refer code section 8.14. Note this is subject to the provisions of section 8.9 with respect to new facilities investment, recoverable portion, depreciation and redundant capital.

[33] Davis & Handley, loc.cit.

flows required to insure/hedge such risks are reflected in operating costs, no further adjustment for risk would appear to be warranted.

The ACCC recognises that time lags are involved in construction before cash inflows are realised. Davis and Handley[34] have advocated that project viability requires that those outlays should be compounded at the required rate of return in determining the cost base of the project.[35] This approach is analogous to the application of the existing provisions of the code regarding the treatment of a speculative investment fund[36] (as opposed to a greenfields type project). The ACCC acknowledges this approach and, consistent with the ACCC's *Draft Statement of Principles for the Regulation of Transmission Revenues*[37], considers that it can be accommodated within the scope of section 8.12 of the code.

The approaches outlined above also ensure the following objectives are met:

- maintaining the economic and financial incentives for the prospective service provider to manage construction in the most efficient manner while ensuring the proper recognition of, and compensation for, those costs prudently incurred
- avoiding the imposition of costs on users for risks that can be adequately addressed during the construction phase and bear no direct relationship to the cost of service for gas haulage
- ensuring risks that are ordinarily and best managed via contractual arrangements continue to be managed in that manner
- ensuring that a prospective greenfields pipeline does not receive compensation that would be additional to what it could receive in a competitive environment.

The provisions for managing construction costs under the code are significantly more flexible and accommodating than in some overseas jurisdictions. For example, in the US the FERC, in its statement of policy, places the financial responsibility for new greenfields gas pipeline development on the prospective service provider. Similarly, the risk of construction cost overruns rest with the prospective service provider, unless it is apportioned between it and shippers in their contracts. Additionally, the prospective service provider is left responsible for the costs of under-utilised capacity and cost overruns.

As part of the FERC's regulatory application process, a prospective service provider has to submit estimated construction cost data for the pipeline project. The FERC will approve transportation tariffs for the prospective service provider taking these construction data into account, along with other relevant cost data and information. Thus, to the extent that the prospective service provider incurs greater construction costs than budgeted for in its submission to the FERC, the prospective service provider will not be permitted to recover these additional costs from shippers through higher tariffs.

However, the FERC has approved a mechanism that provides incentive for prospective service providers to remain within the estimated target costs of a specific pipeline construction project. Under this incentive mechanism the costs of the expansion are subject to a project cost containment mechanism (PCCM). The PCCM establishes a target cost of each new pipeline project. If a prospective service provider manages to carry out the pipeline project for less than the target cost it will share its savings with shippers. If the actual construction costs are higher than the target costs, the prospective service provider has to bear most of these cost overruns.[38]

[34] ibid.

[35] For example, if a project involves an outlay of $1 at date 0, has a required rate of return of r, and generates no cash flows until date 2, the required cash inflow at date 2 is $1(1+r)2 if the project is to have a zero NPV. If target cash flows at date 2 are to be determined at date 1, the appropriate capital base for use at that date is $1(1+r).

[36] Refer code section 8.19(b).

[37] ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999, p. xii.

[38] National Economic Research Associates, Foundation contracts and 'greenfields' gas pipeline developments: experience from the United States and other jurisdictions—final report, March 2002, p. 14.

4.4 Operational phase

Generally, regardless of whether a pipeline is a greenfields investment or a well-established incumbent, it is likely that it faces some form of operational risk. The ACCC understands that once established, the operational risk profile of a greenfields pipeline is unlikely to differ materially from an established pipeline. Accordingly such risks should be treated in the same manner as for established pipelines.

Consistent with the benchmarking approach outlined in the introduction to this section and with the objectives of the code and Part IIIA, costs prudently incurred that are attributable to specific risk mitigation can be included in the operations and maintenance costs of the pipeline. However, this can only apply when such costs are not otherwise compensated for as an element of the costs to which the incentive based benchmarking approach applies. For example, insurance against the event of some forms of failure (other than force majeure events) or loss of transportation tariff revenue.

Service providers also have the option of incorporating a number of other operational risk-related mitigation options. For example, economic depreciation effectively allows for the carry forward of losses in the early years of operation and the derivation of reference tariffs is based on forecast volumes, hence the pipeliner is substantially insulated from volume risks (with respect to cost recovery). Volume risks associated with demand forecasting are discussed in more detail in section 4.5. A pipeliner also has the right to unilaterally seek a review at any time of an access arrangement in the event that its circumstances materially change.[39] CPI–X incentive mechanisms also alleviate a pipeliner's inflation risk.

4.4.1 Self-insurance

In common with mature pipelines, greenfields projects face a number of specific risks that may impinge on cash flow returns available to the venture. Because such risks are non-systematic it is inappropriate to try to reflect such risks in the asset beta established for the regulatory framework. The ACCC maintains that such risks should be compensated for in the cash flow analysis.

As noted above, prudently incurred insurance costs can be included in the operations and maintenance costs (O&M) of the pipeline.

The ACCC understands that a service provider contemplating assuming self-insurance risk would ordinarily conduct a detailed risk analysis to satisfy debt provider and/or corporate governance requirements. Such analysis is likely to include an assessment of the particular risk/s involved, the impact on the business and its cashflow should the event occur and the probability of occurrence.

Accordingly, for a regulator to adequately assess a proposal for self-insurance, in relation to prudency and validation of an appropriate premium, it would need to consider such matters as: a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums; confirmation of the board resolution to self-insure; and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for.

A regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring. In the event of future expenditure required as a result of an insurance event[40] such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operations and maintenance element of the allowed tariffs and funded by users.[41]

Therefore, where the risk is self-insurable and assumed by a service provider, one approach for compensating the service provider would be to adopt a fair actuarially determined insurance premium for each specific risk and include these as part of O&M forecast expenditures.

[39] Refer code section 2.28.

[40] An insurance event refers to an event, which triggers an insurance claim, including a notional claim in the case of self-insurance.

[41] This is also the case for expenditure arising from conventional insurance claims when users have already funded the insurance premiums.

The following are key parameters required to model self-insured events as part of the cash-flow analysis.

- The realistic estimates of the likely occurrence of each type of event. Some probabilities will depend on the age, operating pressure of the pipeline etc. and these can be reflected as time or volume dependent probabilities.

- The expected financial impact of the event, which may be technical or related to legal liabilities. Again such costs must be realistic, for example the cost cannot credibly exceed the asset value of the company at the time of occurrence.

This is precisely the same information required to actuarially determine insurance premiums from a third party perspective but without the truncation of liabilities or risk abatement strategies available to the pipeline company.

4.5 Demand assessment

The ACCC recognises that there is inherent uncertainty in determining demand growth forecasts for a greenfields pipeline, especially where immature or undeveloped demand exists. However, the code provides a high degree of flexibility to facilitate the design of a reference tariff policy that meets the specific needs of each pipeline system.

From a regulatory perspective there are two main implications arising from uncertain demand.

- The difficulty associated with determining a best estimate of forecast demand.

- The increase in potential volume risks, relative to that for a pipeline with greater certainty of demand.

Demand risk faces any new investment proposal regardless of whether the assets are to be regulated or not. However, the possibility of regulation adds another dimension to such risk. Davis and Handley[42] note that should access prices be derived on the basis of applying a required rate of return to an asset base (at some date 2), conditional on an assumed level of future output which is different to that expected at the time the investment was made (date 1), then this approach is not necessarily compatible with providing appropriate signals for investment.[43] For example in the event that the regulatory assessment of expected demand occurred at a point in time after project commitment and after which some aspects of demand uncertainty had been resolved, the reference tariffs determined could vary from those anticipated on commitment.

The ACCC acknowledges this issue and the possible difficulties in managing the inherent uncertainty. As indicated in the consultation sections of this guideline, one potential solution to this problem is to bring forward the regulatory decision date so that it occurs earlier in the project appraisal and development or construction stage rather than after project success has been observed, for example, coincident with financial close of a project.

In such circumstances the regulator will then be assessing expected demand with the same information set and uncertainty considerations that are committed to by the project proponents and its financiers at financial close. Considerations for assessing forecast gas demand are discussed further below, while downside risk mitigation is addressed in section 5. Section 6 deals specifically with the issue that the regulatory framework could potentially compromise the expectations of returns (especially blue sky) thought possible at the time of project commitment.

The regulatory provisions that assist in mitigating demand risk are discussed in more detail in the following sections. Appendix 1 also provides an illustrative example of how uncertain demand scenarios can be modelled to derive an expected return. Together these incentive properties can provide greater flexibility to a prospective service provider than, for example, the approval process in the US. In the US an application for a certificate of public convenience and necessity requires that a prospective service provider applying for such a certificate must have conducted an ‘open season’ before submitting the application.

[42] Davis & Handley, loc.cit.

[43] In this context it is the expected level of demand at the time the project is committed that determines the expected return and hence the incentive to invest.

The open season essentially consists of 'requests for capacity' from potential new shippers as well as 'requests for relinquishment of capacity' in expiring transportation contracts from existing shippers (if the new capacity is an expansion). In this way an open season enables a prospective service provider to assess the demand for its proposed new or expanded pipeline network. However, the open season does not deal with the issue of transportation tariffs for new pipeline development; its principle purpose is to get an indication of shippers demand for new capacity.

4.6 Use of forecasts

The code recognises the requirement for regulators to rely on forecast data in formulating reference tariffs.[44] Such forecasts may need to be determined for:

- capital expenditure
- operations and maintenance expenditure
- demand for volumes over the life of a pipeline.

The ACCC is cognisant of forecasting difficulties and is open to consultation with greenfields pipeline proponents to discuss possible options that remain consistent with the code or Part IIIA.

It should be noted that the level of demand risk is dependent upon the extent to which foundation contracts underpin a greenfields project's viability. For example, a new pipeline supplying gas to a new or immature market faces greater uncertainty regarding future demand than a pipeline that is fully contracted and supplying a well established market. The growth in future demand for a new pipeline can often be dependent upon a number of factors, including new projects securing funding and others remaining operational (e.g. industrial plant or gas fired generation) and/or the rate at which users convert from some other fuel source to natural gas.

[44] Refer code section 8.2.

However, the ACCC notes that for a greenfields pipeline that is likely to pass the regulatory threshold tests, the established industry practice for the purposes of securing debt financing requires a minimum commitment of an appropriate duration from foundation type users to determine the underpinning viability of the project (for a given level of equity contribution).

The ACCC considers that the impact of demand risks on regulatory revenue can be mitigated through careful information analysis and the design of the regulatory arrangements. For example, a number of probability weighted demand scenarios could be used to determine an expected demand (E_D) forecast. An appropriate mechanism could then allow any under recoveries in the early years of an access regime to be subsequently recouped when demand grows.

Forecasts tend to be subject to an inherent element of subjectivity. Accordingly, the code provides for appropriate review mechanisms[45] to be triggered if forecasts diverge significantly from realised outcomes. For example, if a service provider found that discounted tariffs were required to meet its volume forecasts it could seek a review of its access arrangement. Such mechanisms can be designed to ensure they will operate in a way that is understood in advance.

As a preferred alternative, demand scenarios could be linked to a benefit sharing mechanism (discussed below) so that an aberrant demand scenario is catered for in advance. The prospective owner would have adequate scope to capture some of the 'blue sky' potential of a project but some of the benefits would also flow to users. At the same time, such an approach could limit any incentive to skew demand scenario forecasts to the lower end of the spectrum. For example, the best case demand scenario might form the volume or revenue threshold point from which benefit sharing commenced. The benefit sharing mechanism could also be invoked when demand is much worse than expected. In this case users of the pipeline also bear some of the burden and the financial consequences for the pipeline developer are less severe. These options are described in greater detail in section 6.

[45] Refer code sections 3.18, 8.44 and 8.45.

The measures outlined above can give a service provider ex-ante certainty about how an access regime will apply and the likely returns under a range of demand outcomes. Collectively these measures can substantially mitigate the demand risks associated with regulation of a greenfields pipeline. In addition, a service provider has a number of options available to facilitate tariff smoothing/ price path approaches which can be used to optimise demand growth.

The code's approach to demand risk differs from the 'defined capacity' approach adopted by the FERC in regulating gas transmission pipelines in the US. Under a defined capacity approach reference tariffs are based on the pipeline's capacity rather than forecast volumes. *Ceteris paribus*, 'defined capacity' reference tariffs are likely to be lower than if forecast demand is used, particularly in the initial stages of the life of a greenfields pipeline that has been built with excess capacity in the expectation of future demand growth. Compared with the US approach, the code provisions facilitate the transfer of some of this demand risk away from a prospective service provider to customers.

4.6.1 Forecasts, tariffs and incentives for spare capacity

In the US despite prospective service providers having the option of offering different tariff methodologies for transportation services as outlined above, prospective service providers continue to offer mostly cost-of-service based tariffs. Traditional cost-of-service based tariffs in firm transportation contracts generally follow the 'straight fixed variable' method (SFV) of tariff design. Under this method tariffs are structured to enable the prospective service provider to recover its prudently incurred costs and an adequate return on its investments.

Under the SFV method, the tariff for a firm transportation service is made up of two components, a fixed rate and a variable rate — where the fixed capacity component covers investment costs and a variable component covers the marginal costs of transporting gas on a pipeline system.[46] The rationale behind the SFV approach is that most of the costs to obtain firm capacity are fixed, i.e. they are not a function of the amount of gas transported on the pipeline. These fixed costs are apportioned among firm shippers based on the amount of each shipper's reserved capacity on the pipeline.[47]

However, the SFV approach does not guarantee a prospective service provider will recover the fixed costs from 'overbuilt' capacity. It only allows a prospective service provider to recover all fixed costs (independent of gas throughput) for that part of the network that is fully contracted to shippers.

Consequently, if a prospective service provider has only contracted half of its capacity on a new pipeline development, the prospective service provider bears the full risk (and associated fixed costs) for the uncontracted part of the network. The SFV approach applied by the FERC does not allow the prospective service provider to recover fixed costs from uncontracted capacity from existing or new shippers. As a consequence, there are limited incentives on prospective service providers to 'overbuild' new greenfields gas pipelines in the US.[48]

In contrast to the US approach the code provides prospective service providers with a number of options that do not discourage building excess capacity in pipelines. An illustrative example of how the ACCC could assess a prospective service provider's demand forecasts to determine an appropriate reference tariff is provided at appendix 1. As noted above in relation to construction costs, the actual cost of the initial capital base is used as an input to derive a reference tariff based on forecast

46 National Economic Research Associates, Foundation contracts and 'greenfields' gas pipeline developments: experience from the United States and other jurisdictions—final report, March 2002, pp. 21, 36.

47 The fixed portion of a firm shipper's pipeline rate is thus similar to the rent one pays for office or apartment space. The shipper pay a fixed fee to rent 'space' on a pipeline on a contractual basis, regardless of the degree to which the shipper actually uses the 'space' it has contracted for. The cost of reserving that space is proportional to the amount reserved, and the shipper chooses in advance how much is needed.

48 National Economic Research Associates, op.cit., p. 22.

volumes. Importantly for service providers there is also no scope for reassessment of the regulatory asset base at subsequent regulatory reviews, subject to the provisions of section 8.9 of the code.[49] For completeness, the appendix 1 example should be reviewed in conjunction with the risk mitigation, blue sky and consultation sections of this guideline (refer sections 5 to 7 below).

[49] Refer code section 8.14.

5. Additional risk mitigation considerations

This section provides guidance on the scope and flexibility a prospective service provider has under Part IIIA and the code that enable it to mitigate various categories of risk. It also outlines possible mechanisms prospective service providers might consider incorporating when formulating an access proposal. Where relevant the ACCC has enunciated its view about the scope for interpretation and application of the relevant provisions.

As discussed in section 3, the code and Part IIIA of the Trade Practices Act set out a number of principles and requirements that guide regulators and establish the bounds to their discretion. Accordingly the ACCC, as an independent statutory authority, assesses access proposals within these established regulatory frameworks. These bounds therefore provide predictability and certainty about the application of the regulatory framework.

However, within the regulatory framework a prospective service provider has a substantial amount of flexibility when formulating an access proposal. The onus remains with the prospective service provider to submit an access arrangement to the ACCC for assessment that complies with the objectives of the code[50] or an access undertaking, depending on the regulatory option sought.

5.1 Tariff structures and service contracts

5.1.1 Determination of reference tariffs

In an access arrangement, reference tariffs are derived with the objective that service providers may expect to earn a reasonable rate of return on their investment. The reference tariff serves as a benchmark price at which a prospective user is entitled to gain access to services and applies only to the reference service as defined in the access arrangement.

Reference tariffs are limited in their application to third parties seeking access and the code explicitly preserves the right of service providers and users to enter into negotiated contractual arrangements. Similarly, tariffs can be negotiated if the service required by the user is different to the reference service.

The reference tariff regime can be incentive based. For example, it may allow service providers to earn potentially higher returns than the regulatory rate of return by retaining the benefits resulting from market growth and efficiency improvements in areas such as operating and maintenance costs.

In addition the ACCC notes that reference tariffs are derived to ensure service providers can earn a reasonable rate of return on their investment. There is no restriction on a service provider and user negotiating a price above or below the reference tariff, if the service required by the user is different to that provided for by the reference service.

In the US, despite prospective service providers having the option of offering different tariff methodologies for transportation services, prospective service providers continue to offer mostly cost-of-service based tariffs. Accordingly, as noted in section 4.5, the FERC continues to apply a cost based approach with an SFV as the principal methodology for regulating interstate transportation tariffs.

However, under the capacity based approach for determining tariffs the prospective service provider in the US framework is potentially exposed to greater volume risk than under the forecast volumes based approach in the Australian regulatory framework for deriving reference tariffs.

50 Refer code section 8.1.

5.1.2
Contracts in existence before and after an access arrangement

The regulatory approval process for a greenfields pipeline access proposal does not affect the ability of a prospective service provider to contract on negotiated terms with users.

The code does not permit the regulator to deprive a person of pre-existing contractual rights. Nor is there any regulatory intervention into provisions that may be included in any foundation contract. The only exception is for contractual terms relating to exclusivity rights.[51] For example, under section 2.25 of the code, contracts in place before the approval of an access arrangement are preserved.

Further, under Part IIIA the ACCC is prevented from making a determination in an access dispute that would deprive any person of a protected contractual right.[52]

In the case of foundation contracts, the ACCC notes that market participants that may have significant countervailing power and familiarity with the industry may enter into these arrangements. Prudent commercial arrangements for foundation customers might ordinarily include escalation and/or discount provisions, that may be driven by factors such as realised growth in volumes, and share the risks, costs and benefits in a developing market.

5.1.3
Foundation contracts

The role of foundation type customers in Australia is similar to that observed in the US. Long-term transportation contracts in the US that involve financial commitments to reserved capacity by shippers have played a fundamental role in the development of the US gas network and continue to drive new gas pipeline development by sharing long term investment risks between service providers and shippers.[53] At the same time, the regulatory regime has evolved in tandem with market conditions, to provide continued support for efficient gas pipeline development.

The arrangements for new gas pipeline development in the US have the following main characteristics:

- long-term transportation contracts between prospective service providers and shippers that underpin the size, timing and financial risks of new pipeline investments
- an ‘open season’ process that brings together proponents of new pipelines with prospective shippers, before application for certification by the FERC
- a transparent application and certification process under which the FERC assesses new pipeline proposals by reference to whether overall benefits outweigh costs
- the integration of the above processes with an evolving framework for FERC-decisions on whether and how pipeline tariffs should be regulated.[54]

5.1.4
Prudent discounts

It is widely accepted that price discrimination among shippers may increase economic efficiency through increased network utilisation. This will particularly be the case for pipelines that are significantly under-utilised. Consistent with this the Australian code explicitly provides for prudent discounts to be offered by shippers.[55]

The US FERC regulatory model also recognises that selective discounting can promote the efficient use of a pipeline. In the US context discounting generally refers to the cost-of-service based tariffs. The reason is that a discount on transportation tariffs encourages higher network utilisation that generally causes a pipeline’s fixed costs per unit of output to decrease.

In the US prospective service providers are prohibited from granting any undue preference or advantage with respect to any transportation service, requiring that tariffs to similarly

[51] Refer code section 2.25.

[52] TPA, section 44W.

[53] National Economic Research Associates, op.cit., section 2.11.2.

[54] National Economic Research Associates, op.cit., section 4.1.1.

[55] Refer code section 8.43.

situated shippers must not be unduly discriminatory. To ensure that tariffs are not unduly discriminatory the FERC requires prospective service providers to make the discounts available to all 'similarly situated shippers', which are generally defined as shippers that take service over the same part of the pipeline and face the same end-market circumstances. Prospective service providers must file specific information to enable shippers to determine if they are similarly situated to discounted shippers[56] and publish discounts so non-discounted shippers can determine if they are entitled to similar discounts.[57] Prospective service providers that employ discounted rates must file those rates with the FERC.

In contrast to the economic efficiency objectives underpinning the use of prudent discounting, 'most favoured nation' (MFN) type clauses in foundation contracts are optional provisions and potentially prevent prospective service providers from offering different transportation tariffs among shippers.

NERA has observed that to the extent that prospective service providers opt to limit their flexibility to offer discounted tariffs by incorporating MFN clauses in foundation contracts, then capacity utilisation is likely to be reduced, the market will develop more slowly, and the overall efficiency of new pipeline investment is likely to be sub-optimal.[58]

In the US foundation contracts do not generally contain MFN clauses. It is not clear whether or not MFN type clauses have been widely adopted in Australia. However, it is widely understood that price discrimination on a pipeline network generally increases economic efficiency by encouraging increased network utilisation. The ACCC notes the intent of the prudent discount provisions of the code in this regard.[59]

56 *Tennessee Gas Pipeline Co*., 77 FERC ¶61,877 (1996).

57 Order No. 566, FERC Stats. and Regs., Regulations Preambles 1991–1996 ¶30,997 (1994).

58 ibid.

59 Refer code section 8.43.

5.1.5
Market based tariffs

Industry representatives have proposed the use of market-based tariffs for greenfields pipelines but are concerned that they may not be allowed under the Gas Code. The ACCC understands the term refers to a proposal to base the reference tariffs that would be available to third parties on the negotiated tariffs at which foundation customers contract with a service provider.

The fundamental issue to consider under this proposal is whether a pipeline should be regulated. Both the code and Part IIIA provide tests to determine whether services will be regulated. Clearly, negotiated tariffs apply in the case of an unregulated pipeline.

The FERC's January 1996 policy statement on *Alternatives to traditional cost-of-service ratemaking for natural gas pipelines*[60] only permits unregulated tariffs subject to satisfaction of tests that are required to demonstrate a lack of market power for a natural gas pipeline. In summary, the pipeline would have to either:

- demonstrate that it lacks significant market power because users have sufficient good alternatives
- meet specific conditions to prevent the exercise of any market power it may have.

Regulation of gas transmission pipelines in Australia is only applied when natural monopoly characteristics exist and the service provider is capable of exerting some degree of market power.[61] To the extent that the service provider can exert market power, negotiated tariffs would be unlikely to reflect those that would apply in a competitive market. This is consistent with the Brattle Group's observation that there is no evidence that negotiated access regimes have produced any of the positive benefits, such as superior innovation of flexibility, that are sometimes cited in favour of negotiated access.[62]

60 FERC, Alternatives to traditional cost-of-service ratemaking for natural gas pipelines (Docket No. RM95-6-000), 31 January 1996.

61 In Australia the National Competition Council (NCC) assesses market power.

62 The Brattle Group, *Third-party access to natural gas networks in the EU*, March 2001, p. 2.
Copies of this report are publicly available on the website of the European Federation of Energy Traders at <http://www.efet.org>.

When regulating pipeline services, the ACCC is required to comply with the code provisions or Part IIIA requirements which include having regard to the cost reflectiveness of access pricing proposals and providing the service provider with the opportunity to earn a reasonable return on its investment. In the case of the code, a reference tariff operates as a benchmark tariff for a specified reference service while meeting the code objectives.[63] Accordingly, in principle a negotiated tariff would only be expected to be greater than a reference tariff to the extent that the service provider can exert market power.

The ACCC is only concerned with the regulation of natural gas transmission pipelines that either meet the coverage tests under the Gas Code[64] or are subject to an access undertaking or declaration[65] under Part IIIA of the TPA.

- Under either regime, access prices are designed to provide a reasonable return to the service provider. In this regard the regulatory framework affords considerable certainty to prospective service providers.

- Where a negotiated tariff exceeds a reference tariff it would appear that the negotiated tariff would be providing the pipeline owner with a greater than normal return.

5.2 Determining the initial capital base for a greenfields pipeline

Section 8.12 of the code provides for the initial capital base (ICB) of a new pipeline to be included at the actual capital cost of the assets at the time they first enter service.[66] And there is no scope for reassessment of actual cost in subsequent regulatory reviews.[67] This contrasts with the treatment of existing pipelines where the regulator must consider valuations based on methodologies such as depreciated actual cost and depreciated optimised replacement cost. Part IIIA does not provide this degree of prescription and certainty to greenfields investors. However, the ACCC is likely to value the ICB at actual cost unless there is strong reason to do otherwise.

The ACCC is aware that the costs of a greenfields pipeline may not be known with precision until some time after operations commence and that initial reference tariffs would need to be determined based on forecast capital and non-capital costs.

The ACCC considers that a forecast ICB could be used when determining the initial reference tariff in conjunction with an appropriate mechanism to adjust the tariff when the actual capital cost is known with certainty.

5.2.1 Adjustment mechanisms

The ACCC considers that section 8.12 of the code provides sufficient flexibility to allow the inclusion of a symmetric adjustment mechanism to accommodate any material variance between the forecast and final cost of the ICB.

Incorporating an appropriate adjustment mechanism would:

- alleviate any downside risk to the service provider in the event that the final cost of the ICB was greater than forecast

- pass through benefits to users in the event that final cost was lower than forecast.

An appropriate adjustment mechanism would be expected to: mitigate under or over recovery; avoid potential discontinuities in the reference tariff price path to avoid volatility in tariffs; and provide certainty for users.

While the design of the adjustment mechanism would largely depend on the service provider, the ACCC expects that both the timing and dollar cost effects could be parameterised and clearly expressed from the date of commencement of the access arrangement. Prospective users could then contract for capacity at the reference tariff (with ex-ante

[63] Refer code section 8.1.

[64] As determined by the NCC.

[65] As determined by the NCC.

[66] Refer code section 8.12.

[67] Refer code section 8.14. Note this is subject to the provisions of section 8.9 with respect to new facilities investment, recoverable portion, depreciation and redundant capital.

certainty as to the methodology for calculating any variance in tariffs once the actual ICB is known). As noted above, parties also retain the right to negotiate for access.

A range of appropriate adjustment mechanisms is possible. The optimal approach from the service provider's perspective is likely to depend on the weight it attaches to stability in reference tariffs as compared to the speed of cost recovery, noting that either approach would be equivalent in net present value (NPV) terms.

An illustrative approach to adjustment mechanisms is outlined at appendix 2.

5.3 Downside risk mitigation

Section 2.28 of the code provides that the service provider may seek revisions to its access arrangement at any time. In contrast the ACCC cannot initiate an early review.[68] Similar provisions apply to an access undertaking under Part IIIA. That is, a service provider may withdraw or vary an access undertaking at any time, but only with the consent of the ACCC.[69]

These provisions afford protection to a prospective service provider in the event that unforeseen factors affect it and constrain its ability to earn a reasonable return.

Thus, service provider initiated, unscheduled revisions to an access arrangement can assist a service provider who finds unforeseen factors significantly impinging on its ability to earn a reasonable return. Further, where demand is expected to grow gradually over time, a depreciation profile may be chosen that allows the opportunity for expected early under recoveries to be recouped in later years. This is discussed in further detail in section 6.5 of this guide.

[68] Specific major events may require a service provider to submit revisions under the code. Refer code section 3.17(ii).

[69] TPA, s. 44ZZA(7).

6. Managing uncertainty and blue sky opportunities

A criticism levelled at regulators by prospective investors is that perceptions of regulatory risk in a regulated industry act as a disincentive to investment. These perceptions are on the assumption that a regulated entity's downside risk is not capped whereas its 'blue sky' opportunities are, including the potential for regulators to claw back or otherwise limit the blue sky potential of a new investment at the next regulatory review.

These views fail to recognise the provisions of the code that mitigate both of these risks while ensuring compliance with the code's objectives of earning a reasonable return to service providers and benefit sharing with users. These are outlined further below. Prospective service providers are encouraged to discuss such options with the ACCC when formulating access arrangements for regulatory approval.

It is also instructive to note that in its paper on natural gas pipeline access regulation[70], NERA found the code to be a sound piece of regulatory legislation and demonstrated that appropriate access regulation will not deter investment in gas pipeline infrastructure. On the contrary, NERA found that sound regulatory regimes contain numerous provisions that promote rather than discourage gas pipeline investment, and appropriate regulatory regimes provide risk-averse investors with the certainty they require for their investments. In a survey of declared post tax regulatory rates of return across various jurisdictions in the United Kingdom and North America it was found that Australian regulators were providing higher vanilla post-tax weighted average costs of capital than in the other jurisdictions examined.[71] Similarly the Brattle Group noted in its comparative analysis of tariffs in the European Union that where prices were transparently linked to underlying costs they were generally substantially lower than those that were not.[72]

The code recognises that to encourage investment, a prospective service provider should be given the opportunity to reap some of the blue sky potential of the pipeline, where prospective blue sky profits are needed to offset prospective losses from a dismal (black sky) outcome. Further, the investor needs regulatory certainty on the treatment of abnormal (extreme scenarios both optimistic and pessimistic) returns during the initial forecast time horizon and certainly during the initial regulatory period/s. The inclusion of an incentive mechanism in an access arrangement[73] (or access undertaking) is an important component of a service provider's regulatory framework. The ACCC encourages service providers to develop mechanisms that will best suit their particular needs.

Without constraining the intentions of the code in this regard, the challenge for regulators is to assess access regime proposals that establish a framework which ensures the service provider's economic incentives to maximise utilisation of its assets and development of its business while not imposing unreasonable cost transfers to users.

A number of options are available to prospective service providers when formulating an access proposal that can provide certainty in the context of both blue sky and black sky scenarios. These include the term of the access arrangement/undertaking period; benefit sharing mechanisms; fixed principles, downside risk mitigation review triggers;

70 Natural gas pipeline access regulation—Report for BHP, 31 May 2001

71 National Economic Research Associates, International comparison of utilities' regulated post tax rates of return, March 2001.

72 The Brattle Group, *Third-party access to natural gas networks in the EU*, March 2001, p. 24. Copies of this report are publicly available on the website of the European Federation of Energy Traders at <http://www.efet.org>.

73 Refer code section 8.44.

depreciation schedules and any combinations thereof. Each of these is discussed below.

Additionally the ACCC is receptive to other proposals from prospective service providers to mitigate the risk profile of a greenfields pipeline, provided it is consistent with the objectives of the code or Part IIIA, depending on the access regime sought.

6.1 Demand forecasting

The ACCC acknowledges the inherent uncertainty a prospective service provider is likely to face in forecasting demand volumes and growth profiles, beyond its contracted foundation customer base, in immature or undeveloped markets.

The ACCC understands, irrespective of whether a greenfields pipeline is to be regulated or not, that during the investment analysis phase for a prospective greenfields pipeline the proponents conduct substantial market analysis. This detailed analysis to determine the projects likely demand and growth potential, and to secure the levels of commitment necessary from foundation customers to ensure the economic viability of the project, is understood to be an essential precursor to securing the necessary board and financing approvals.[74]

As noted above, demand forecasts will be a function of the underpinning foundation type contracts including contracted or planned expansion in foundation customer demand, and market analysis of likely demand from third party users and rate of growth in that demand. Accordingly the ACCC considers that an expected demand forecast can be modelled to account for the inherent uncertainty for the purposes of deriving a reference tariff. Demand risks could then be mitigated through the analysis of a number of probability weighted demand scenarios to provide a known revenue profile to the prospective investor for each demand scenario proposed.

While there is an inherent element of judgment associated with forecasts, the code provides for appropriate review mechanisms[75] in the event that forecasts diverge significantly from realised outcomes. For example, mechanisms are available to ensure that under recoveries in the early years of an access regime can be compensated for in the regulatory framework.

The ACCC notes that the use of such a framework may increase the incentive for prospective service providers to 'game' its expected demand forecasts. For example, a prospective service provider could have the incentive to skew, or weight, forecast demand probabilities in favour of less optimistic outcomes (while still maintaining an NPV not less than zero), thus leading to a lower expected demand and a higher reference tariff.

However, if this approach was adopted, it could potentially result in an adverse outcome for the service provider such as negative implications for longer term market development (regarding price signalling) and the lowering of a benefit sharing threshold point (see 6.2 below). The formal approval process of an access proposal also requires public consultation that would provide an opportunity for interested parties to comment on the proposed demand forecasts.

Accordingly, an effective framework needs to establish an agreed basis that provides certainty at the outset and incentives for a prospective service provider to maximise the use of its reference service and earn a greater than normal return up to a pre-determined point and for a known period. The ACCC considers that the inclusion in an access proposal of a threshold point from which benefit sharing should occur, is an appropriate mechanism.[76]

6.2 Benefit sharing mechanisms

There is a range of benefit sharing mechanisms that a prospective service provider could consider when formulating an access proposal. A benefit sharing mechanism would involve

74 Macquarie Bank Limited, Issues for debt and equity providers in assessing greenfields gas pipelines, May 2002.

75 Refer code section 3.18.

76 In the case of an access arrangement the threshold would need to be formulated in accordance with review mechanisms set out in section 3.18 of the code.

the inclusion of a methodology for the sharing of greater than expected revenues between the service provider and users, and may also identify an event that will invoke the benefit sharing provisions. The inclusion of such a clause in the access arrangement or undertaking would provide the service provider with certainty from the outset, regarding the nature and effect of any benefit sharing and at what point it will commence. Possible mechanisms could be based on:

- demand focused capacity/volume thresholds
- revenue based
- profit based
- a combination of the above.

Expected demand, revenue and profit scenarios can be linked to any benefit sharing mechanisms that may be required. This would ensure the appropriate incentive to capture some of the blue sky potential of a project and alleviate the potential incentive to skew demand scenario forecasts to the lower end of the spectrum.

It should be noted that the inclusion of a benefit sharing mechanism does not involve or represent a review of the access proposal before the expiration of the agreed regulatory period, in any way. Rather, benefit sharing would only commence once a threshold point has been reached and would follow the methodology previously agreed upon and set out in the approved access proposal.

The ACCC also notes that the benefit sharing mechanism would only come into operation after the prospective service provider has been adequately rewarded for undertaking the investment, and the service provider would still continue to receive a financial benefit from any further growth in demand.

An illustrative example of one possible form of a potential benefit sharing mechanism to apply once the threshold has been reached is provided at appendix 3. This example is based on a demand focused volume threshold. Note that in this example any further increase in demand beyond the threshold continues to be revenue and profit cumulative to the service provider, albeit at a reduced rate. The benefit sharing mechanism would only be initiated once a pre-determined volume threshold had been reached. As outlined above the ACCC envisages that such a threshold would be set such that the prospective service provider would realise and retain the blue sky benefits it identified as potentially realisable in deriving its expected demand, before the benefit sharing provisions took effect.

It should also be noted that the sharing mechanism proposed at appendix 3 is symmetric in that the costs to the pipeline developer of abnormally low demand is diminished with potential users of the pipeline sharing those costs in higher future tariffs.

6.3 Preservation of blue sky profits

A major concern of the pipeline industry seems to be that the regulatory framework will operate in a non symmetric fashion so that at the first review of an access arrangement the regulator will observe the current demand levels then revise reference tariffs on the basis of these more certain demand forecasts. When these new forecasts are higher than the average of the forecasts proposed initially this implies a reduction in tariffs relative to what would have been reasonably expected at the time of commitment to the pipeline proposal. The asymmetry emerges from the fact that if demand turns out to be worse than expected then raising tariffs to restore the required return may not be possible with weak levels of demand.

This is illustrated in figure 6.1 below. The revenues shown in this figure are based on the revenue sharing example in appendix 3. The three upward sloping revenue lines are the revenues expected under the three scenarios from tariffs set at the commitment stage of the pipeline project. Of course each of these revenue streams gives rise to a different achieved return to capital as was expected ex ante. These ex ante returns are recorded in the first column of table 6.1.

However, if the first regulatory review for the period commencing period 6 was based on demand observed at that time, then the tariffs necessary to maintain the required rate of return into the future would be different to those based on the average of the three potential scenarios considered possible at the time of project commitment.

It is clear that both scenarios two and three could sustain the required WACC from period 6 with a lower tariff than determined initially. If this was the basis for setting tariffs for period 6 onwards the revenue stream expected in scenarios two and three would be that given by the dark horizontal line shown in figure 6.1, capping revenues at $75 million.

Of course, if this was the expected regulatory treatment, using the ex post observation of actual demand, then the expected returns would be less than those at the outset without a regulatory reset and there would be an inadequate return to justify the investment. The lower returns are shown as column two in table 6.1. The average over the three scenarios is 7.6 per cent, below the required WACC of 8 per cent.

The purpose of this section is to confirm that this is **not** the proposed regulatory framework that the ACCC would apply to greenfields investments. Instead, subject to the length of the initial regulatory period and the relevant forecast interval, a regulatory reset need not be based on observed demand at a periodic review. In such reviews the forecast probabilistic scenarios would be maintained for the timeframe over which they were made. Beyond that point it would be expected that market demand would have stabilised at a level which would make the application of the standard approach to regulation for mature pipelines more appropriate.

An obvious concern is whether this approach is invalidated when demand forecast scenarios are proven to be incorrect. This may be a result of dramatically higher or lower outcomes. The answer to this question must be no. That is why the introduction of the benefit sharing mechanism is important. It does not correct for an invalid set of forecast scenarios but it does moderate the impact towards the regulatory outcome that would have emerged had a better set of forecasts been made.

The impact of revenue sharing is shown in the third column in table 6.1. The returns achievable in the upper (scenario 3) and lower (scenario 1) demand scenarios are modified slightly, but the expected return on capital is not compromised and remains at 8.0 per cent.

Appendix 3 gives further examples of what happens with revenue sharing when outcomes are much higher/lower than forecast.

The key reason why the forecasts cannot be revisited even when proven incorrect is that it is impossible to come up with a completely accurate set of ex ante forecasts at project commitment. Although the robustness of the ex ante forecasts is likely to be related to the proportion of foundation customers, their veracity can only be assessed once actual demand levels have been observed.

Under the gas code the regulator cannot initiate a review of an access arrangement when circumstances are observed to change except at a review.[77] The important point here is that the regulator will not take account of updated demand forecasts even at the time of a scheduled review occurring in the forecast time horizon.

In contrast to the options available to the regulator, the service provider may seek a review on the basis of changed circumstances. However, an important corollary of the approach outlined here is that a shortfall in demand expectations cannot be used as the basis for raising reference tariffs. Instead, the revenue sharing mechanism also provides the downside protection likely to be sought by the service provider. As noted in appendix 3, the protection is unlikely to come in the form of higher immediate tariffs (which would have the effect of reducing demand further) rather capitalisation of financial losses is the preferred mechanism. This enables a more satisfactory return to be achieved even in a black sky scenario but over a longer timeframe. Of course, not all financial loss can be compensated for in a sharing mechanism. The amount will depend on the level of sharing established as part of the sharing mechanism. A higher level of sharing provides greater protection but also shares more of the blue sky profits with customers.

[77] Specific major events may require a service provider to submit revisions under the code. Refer code section 3.17(ii).

Figure 6.1 Revenue expected from three different 10 year demand scenarios proposed with and without reassessment of demand expectations at first review for the period commencing in period 6.

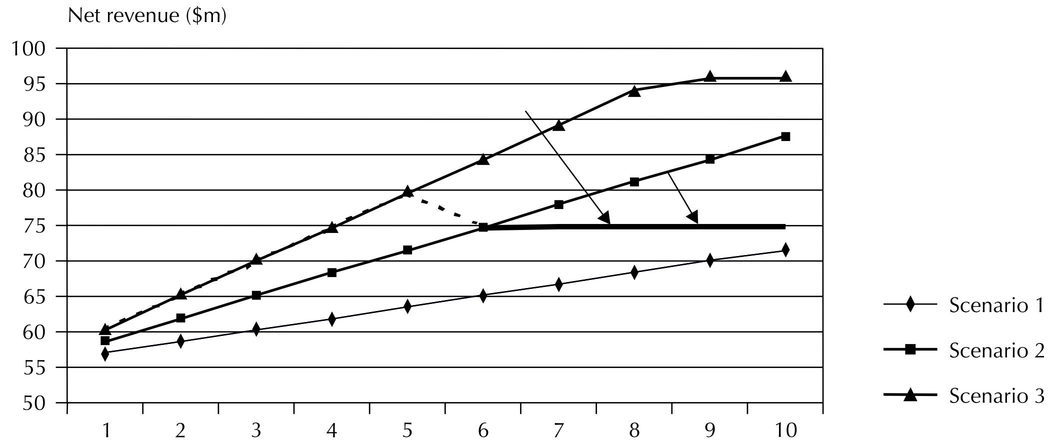


Table 6.1 Estimates of achievable return (WACC) on capital in different scenarios (%) over 10 years

Scenario	Ex ante[1]	Ex post[2]	Sharing[3]
Low (scen. 1)	7.0	7.0	7.2
Middle (scen. 2)	8.0	7.7	8.0
High (scen. 3)	9.0	8.0	8.8
Average	8.0	7.6	8.0

Notes: 1. Ex ante no recontracting.

2. Ex post if recontracting occurred for years 6 to 10.

3. Sharing with no recontracting.

6.4 Duration of an access arrangement

The code allows the regulator to consider an access arrangement period of any length. However, when the access arrangement period is greater than five years the code requires the regulator to consider whether mechanisms should be included in case the risk of forecasts on which the terms of an access arrangements were based and approved were incorrect.[78]

The ACCC's final decision for the Central West Pipeline (CWP)[79] provided for an access arrangement period of approximately 10 years. The extended period was to provide the service provider with an additional incentive to develop the natural gas market in the central west and (potentially) central ranges.

By allowing for a longer access arrangement period, and in conjunction with any benefit sharing mechanism as outlined above, the service provider is able to retain for a longer period any higher returns it earns from outperforming its forecasts. In effect, the business has the potential to earn, and retain for an extended period, a rate of return higher than the benchmark set by the ACCC. The ACCC considers that a longer period provides a greater incentive to the service provider to improve its performance and build its markets and the opportunity to reap more of the project's blue sky potential. Under the code, in the event that expected returns are not realised

[78] Refer code section 3.18.

[79] ACCC, Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline final decision, 30 June 2000.

service providers are also able to seek a review at any time.[80]

With regard to Part IIIA, while an access undertaking must specify an expiry date, no maximum or minimum term is specified.[81] Therefore, as with the code, the term of an access undertaking is flexible.

6.5 Fixed principles

The service provider can also seek to ensure certainty for the application of structural elements of the access arrangement by incorporating fixed principles in its reference tariff policy.[82] Fixed principles may include any structural element. A fixed principle may not be changed without the agreement of the service provider for a specified period, the fixed period. However, in determining the fixed period regard must be given to the interests of the service provider, users and prospective users.

Sections 8.47 and 8.48 of the code deal with fixed principles. They provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods. In this way a pipeline company seeking certain provisions to be sustained over a long term can do so without necessarily having to propose a very long access arrangement duration. Structural elements specifically include:

- the depreciation schedule
- the financing structure
- that part of the rate of return that exceeds the return that could be earned on an asset that does not bear any market risk.

These provisions can give investors long-term regulatory certainty over how their investment will be treated. The provisions clarify parameters over which the regulator might otherwise seek to exercise discretion and which could leave investors unclear about future regulatory changes.

[80] Code section 2.28.

[81] TPA, s. 44ZZA.

[82] Refer code section 8.47.

6.6 Depreciation

Under the code a depreciation schedule should reflect the following principles:[83]

- the change in reference tariffs over time is consistent with the efficient growth of the market for the services provided
- depreciation occurs over the economic life of the asset(s) with progressive adjustments where appropriate to reflect changes in expected economic lives
- an asset is depreciated only once and that total accumulated depreciation will not exceed the valuation of the asset when initially incorporated in the capital base.

Standard straight-line depreciation over the economic life of the asset has typically been the methodology used when depreciating a pipeline's capital base. However, provided that the principles of the code are adhered to, a service provider is able to use an alternative approach.

For example, the ACCC's CWP final decision provided for the use of economic depreciation as part of the service provider's NPV/price path methodology to determine total revenue. Economic depreciation was calculated in the following manner:

> Economic depreciation = total revenue – operating costs – return on capital

The ACCC approved, with qualifications[84], the service provider's proposed economic depreciation approach in recognition of the beneficial effect it would have in allowing the service provider to recoup under-recoveries accrued in the early period of the life of the CWP. This approach also provided lower tariffs during the initial phase of the life of the CWP, enabling greater opportunities for market development. This approach to depreciation was considered consistent with the code objective that the service provider should have the opportunity to earn a stream of revenue

[83] Refer code section 8.33.

[84] ACCC, Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline final decision, 30 June 2000, pp. 68–72.

that recovers the efficient costs of delivering the reference services over the expected life of the assets.[85] This approach is particularly helpful for new pipeline developments where full cost recovery would imply high initial tariffs and consequently poor take-up of available capacity. The approach means that the company can charge lower tariffs initially and encourage gas usage without incurring a non-recoverable financial loss.

Part IIIA does not specify any particular depreciation methodologies. Consequently a prospective service provider has equal flexibility in tailoring an appropriate depreciation methodology to meet its requirements.

6.7 Post-tax revenue handbook

The ACCC released the *Post-tax revenue handbook* and related model (PTRM)[86] in October 2001. The handbook presents a simplified model that provides interested parties with an overview of the post-tax revenue model as applied by the ACCC in its regulation of various Australian utilities.

Prospective service providers can apply the concepts outlined in this document and examples to determine the necessary inputs for the PTRM and thus derive indicative unadjusted and smoothed reference tariffs. Subject to the robustness of input data, the outputs derived in this manner will be indicative of the ACCC's approach to assessing a prospective service provider's access proposal.

The PTRM also includes a normalisation module and an example of the normalisation approach that can be adopted to avoid revenue or price volatility in the face of rapid changes in a service provider's tax liabilities by adjusting depreciation to offset tax costs in an NPV neutral manner.

85 Refer code section 8.1(a).

86 Electronic copies of the handbook and model can be found on the ACCC's website under <http://www.accc.gov.au/gas>

7. Consultation and provision of information

The ACCC notes that there are significant similarities between the processes that it must follow when assessing access arrangements and access undertakings. Both require it to undertake a public consultation process and, as noted earlier, the ACCC will consider similar frameworks in assessing any application.

7.1 Consultation before submitting an undertaking or access arrangement

As discussed throughout this guideline, a prospective service provider has a number of options available when formulating an access arrangement or undertaking that best addresses the requirements and risks of its particular pipeline project. The ACCC welcomes open and constructive discussions with prospective service providers to facilitate the development of an appropriate regulatory approach that recognises the particular circumstances of a proposed greenfields pipeline project. The ACCC has developed this guideline to provide users with certainty of regulatory outcomes.

To provide a preliminary non-binding view on reference tariffs to a prospective service provider, the ACCC will require sufficient information to complete its assessment. While the prospective service provider would not be bound to provide the information discussed in the next section, the ACCC would consider this a good indication of the information necessary to provide a considered and informed assessment of likely reference tariffs. Notwithstanding issues raised during public consultation, the accuracy of the ACCC's preliminary views are very much dependent upon the amount and relevance of the information provided.

The ACCC would consider the process of providing a preliminary view as confidential in nature and any information provided by the prospective service provider, including the outcome of the assessment, would be treated as **commercial in confidence**.

In the event that a formal application is made the ACCC is then bound by the consultation provisions of the code or Part IIIA, depending on the nature of the regulatory regime sought, and service providers are required to provide all relevant information.

Where possible the ACCC aims to preserve the confidentiality of commercially sensitive information during the formal consideration of an access regime proposal. Prospective service providers are referred to sections 7.11 to 7.14 of the code and page 70 of the *Access undertakings* guideline for the position on preserving confidential information for access arrangements and undertakings respectively.

7.2 Provision of information

Under the code, a service provider is normally required to submit access arrangement information in conjunction with its proposed access arrangement. Section 2.7 of the code states that the access arrangement information may include any relevant information but must include at least the categories of information described in attachment A to the code (a summary of which is shown in Box 7.1).

The access arrangement information must contain sufficient information to enable users and prospective users to understand the derivation of the elements in the proposed access arrangement and to form an opinion as to the compliance of the access arrangement with the provisions of the code.[87]

[87] Refer code section 2.6.

Box 7.1. Summary of attachment A information

The information required is divided into six categories:

Category 1: access and pricing principles

Tariff determination methodology; cost allocation approach; and incentive structures.

Category 2: capital costs

Asset values and valuation methodology; depreciation and asset life; committed capital works and planned capital investment (including justification for); rates of return on equity and debt; and debt/equity ratio assumed.

Category 3: operations and maintenance costs

Fixed versus variable costs; cost of services by others; cost allocations, for example, between pricing zones, and cost categories.

Category 4: overheads and marketing costs

Costs at corporate level; allocation of costs between regulated and unregulated segments; cost allocations between pricing zones, services or categories of asset.

Category 5: system capacity and volume assumptions

Description of system capabilities; map of piping system; average and peak demand; existing and expected future volumes; system load profiles and customer numbers.

Category 6: key performance indicators

Indicators used to justify 'reasonably incurred' costs.

In the case of an access undertaking, Part IIIA does not prescribe the information that should be provided in an access undertaking. However, the ACCC's *Access undertakings* guideline does provide a broad list of information that could be included in any proposal for any access undertaking.[88] As discussed earlier, the two regimes are very similar and it is likely that the same type of information would be necessary to assess the application under either access regime. Therefore, prospective service providers submitting an access undertaking should also be guided by the information set out in attachment A of the code.

As noted in section 5.2, actual capital costs will be used to value the initial capital base for a greenfields pipeline once it is completed. However, in the case of a pipeline yet to be constructed or still under construction, the actual capital costs of the pipeline are not yet known. In the case of future capital expenditure and operating and maintenance costs, both new and established pipelines are required to provide forecast values. While these costs may not be as easily ascertained for a new or proposed pipeline, it is highly likely that they will fall within a fairly limited range.[89]

7.3 Public consultation and assessment procedures

The public consultation and assessment procedures are essentially the same for both an access undertaking and an access arrangement. A service provider submitting an undertaking can vary or withdraw it at any

[88] See ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999, p. 65.

[89] Refer appendix 2.

time subject to the ACCC's consent. However, under the code, only a service provider who has submitted a voluntary access arrangement[90] (that is, a pipeline that has not been deemed covered) can withdraw its access arrangement before approval. Although service providers subject to an access arrangement under the code may submit to the regulator proposed revisions at any time.[91]

Further, while the ACCC is required to issue a draft decision under the code, the ACCC can exercise its discretion to issue a draft report for an undertaking depending upon whether any difficult or controversial issues have been raised. Box 7.2 outlines and compares the public consultation and assessment procedures for both an access undertaking and an access arrangement.

7.4 Timeliness of regulatory rulings

The assessment of access regime proposals, provision of all relevant information by a service provider and required public consultation processes outlined above necessitates an assessment period of several months. The code[92] provides that the regulator must issue a final decision within six months of receiving a proposed access arrangement.

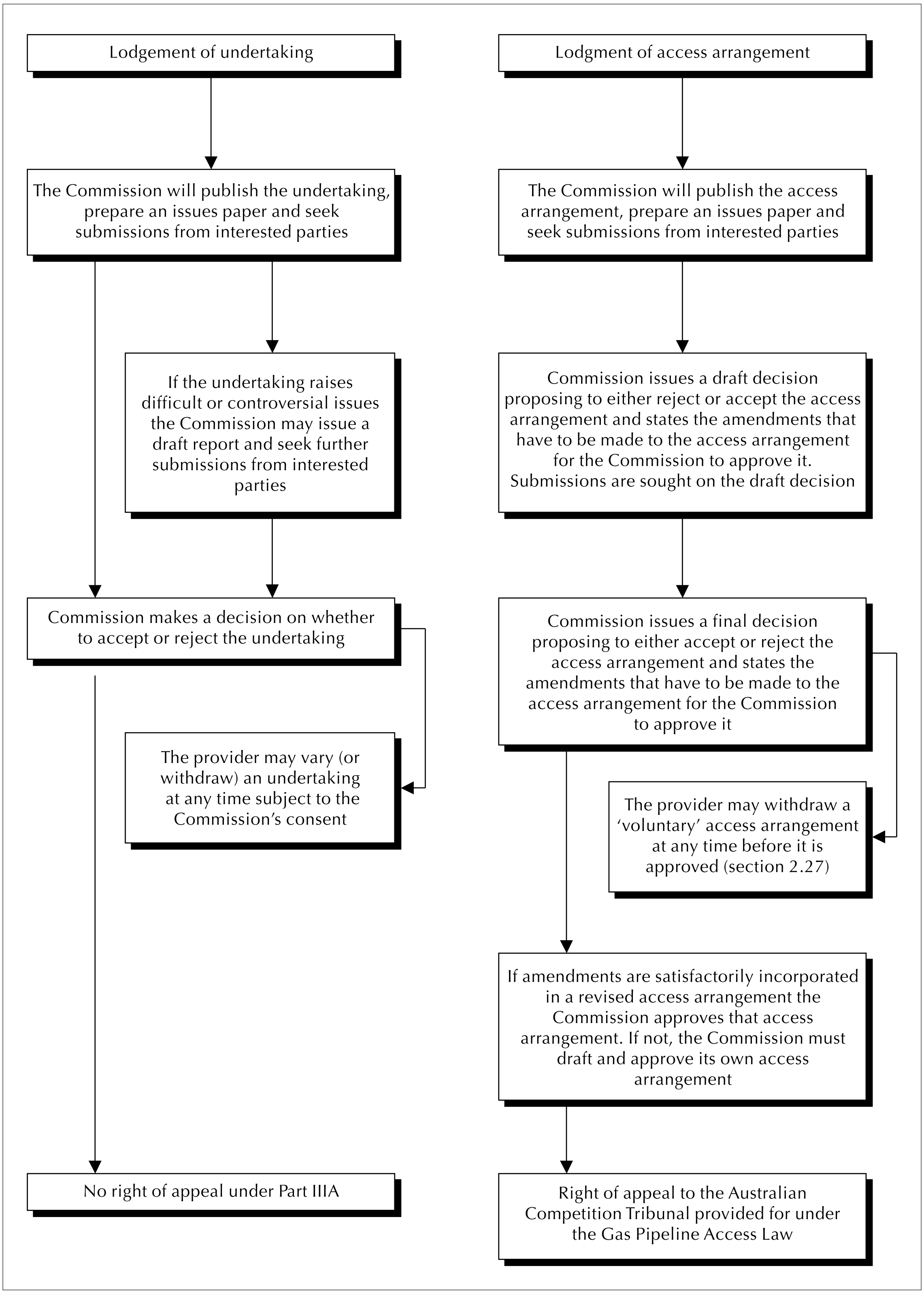
Six months is considered to be a reasonable length of time, given the long lead times inherent in gas pipeline investments and time needed for consultation and due process. The ACCC notes that any delays in issuing an access arrangement final decision is likely to be a concern for providers of capital. To mitigate timing uncertainties for regulatory decisions regarding greenfields pipeline projects it is incumbent on project proponents to pro-actively manage regulatory determination processes to ensure the regulator is able to promulgate determinations within the minimum prescribed timeframe.

90 Refer code section 2.3.

91 Refer code section 2.28.

92 Refer code section 2.21 (subject to 2.22).

Box 7.2. Comparison of public consultation and assessment procedures



Appendix 1

Example for derivation of revenues when expected demand is uncertain

The following example sets out one possible approach to setting parameters of customer demand survey results and determining expected returns where there is uncertainty. The ACCC notes that there may be many ways of developing such a framework. However the following example is provided.

In a greenfields project part of the demand is underwritten by foundation contracts but a part of expected demand is uncertain and may not emerge as envisaged despite market research. This example quantifies aspects of uncertainty inherent in forecasting demand and growth factors beyond the certainty provided by foundation contract type commitments. Assessment of the information set outlined in this example is consistent with the due diligence type requirements of debt and equity providers in their respective analyses of a pipeline proposal.

Interesting points to note in the following example are:

- the manner in which a large number of simulations for a number of customer classes with varying take up rates can be modelled
- how capacity constraints impact on the blue sky earnings capability of a given pipeline specification, thus enabling project proponents to assess the optimal sizing and amount of spare capacity to build into a pipeline from the outset.

The basic question of future demand is just as critical for investment decisions concerning whether to build the pipeline and its optimal diameter/sizing as it is for any regulatory decisions concerning tariffs. The nature of information required is the same for both tasks. Both require an appreciation of who the potential customers may be and what their energy demands are likely to be. For existing users of energy in the region served this requires an assessment of the delivered gas price that would lead them to switch to natural gas as a primary source of energy, the capital costs involved in doing so and how long this may delay any such switchover. In addition there will be other potential customers who may emerge because of the availability of gas supply. The delivered gas price will be important in determining what new businesses may be attracted.

To be better informed on these issues it should be possible to survey customers about their likely needs. It is not expected that such a survey will eliminate uncertainty. It is likely that considerable uncertainty would remain about the intentions of many potential customers. However, such a survey would allow a probabilistic appreciation of the potential market.

For each customer it is expected that the pipeline proposers could develop an opinion concerning the following:

- the existing energy needs of a customer and whether these are likely to expand
- the delivered price of gas at which the customer is likely to find gas a more economical energy source in the long term
- short term factors such as new capital costs that may prevent or delay early adaptation
- the impact that the delivered gas price is likely to have on a customer's choice of energy and timing of any changeover decision
- other factors influencing a customer's decision to become a gas user.

There will be concerns regarding some responses and overall considerable scope for subjective interpretation of any information provided by potential customers. Nevertheless, any serious attempt to compile such information will help define the nature and extent of uncertainty concerning possible demand. The mere act of identifying potential customers is a major advance even before questions concerning their costs and needs are explored.

There are many ways of developing such a framework. Below, just one possible approach to setting parameters of customer demand survey results is considered.

Customer specific demand forecasts

A customer's existing demand for energy is estimated to be E(0) and this demand is expected to increase by x per cent of GDP growth g (or a similar index of economic activity). On the basis of the existing energy source (which may be LPG, electricity, diesel etc.) it could be estimated that the price of delivered gas that would make a switch to gas as the energy source economically attractive in the short term is A(0), in the absence of other switching costs.

This switching price may be expected to vary as time progresses according to A(t). This may link to the rate of change in alternative fuel sources (say a(t) per annum). However, an immediate switch may be ruled out because of changeover costs and existing operational plant which is too costly to replace immediately. The effect of such changeover costs is to reduce the threshold price at which gas becomes economically attractive. This impact could be assessed as K(0) which is the amount the gas price P(0) would need to be below A(0) to achieve an immediate conversion. This discount can be expected to reduce over time as existing plant is written off and needs replacement, say in L years time. A simple linear expression for variation of the conversion discount over time could be used to approximate this aspect of the decision:

$$K(t) = K(0) \cdot t / L \qquad (1)$$

To determine what transport tariff is needed to attract the customer the well head gas price G(t) needs to be subtracted.

Setting these parameters identifies the period (t) in which the customer changes over to gas according to whether the following relation is true

$$P(t) < A(t) - K(t) = A(t) - K(0) \cdot t / L \qquad (2)$$

The price of alternative fuels A(t) is determined by the process

$$A(t) = A(t-1) \cdot (1 + a(t)) \qquad (3)$$

where a(t) is the growth in alternative fuel prices from the previous year.

The quantity of gas is likely to be fairly insensitive to the transport tariff and would be equal to

$$E(t) = E(t-1) \cdot (1 + x \cdot g(t)) \qquad (4)$$

The service provider has some discretion when conversion may take place by setting the tariff

$$\begin{aligned} T(t) &< P(t) - G(t) \\ &< A(0) - K(0) \cdot t/L \qquad (5) \end{aligned}$$

In any event if this inequality holds it assumes that the potential customer switches to gas in period t and contracts for E(t) units and continues to use gas as its main fuel source thereafter.

This form of analysis can be considered for a range of customer types and the survey results expanded to develop a picture of the overall market.

Setting such parameters suggests what may be the appropriate sizing of the pipeline, the optimal discount to offer foundation customers and an efficient time profile for change in tariffs.

This is a rather simple characterisation of customer behaviour but there is no reason why it can not be made as sophisticated as desired by the pipeline sponsor.

Setting the parameters does not require a high degree of precision and certainty. First of all it is unlikely that the survey will be exhaustive and will therefore require some extrapolation to the market as a whole. Secondly, customers being surveyed may be indefinite about their requirements and the surveyor may need to qualify the results with subjective estimates based on experience and secondary information sources. Thirdly a service provider may constrain itself by charging the same tariff to all customers.

The degree of uncertainty associated with each parameter then becomes an integral part of each assessment. For simplicity we assume below that such uncertainty is expressed as a normal distribution with the standard deviation chosen to reflect the degree of uncertainty.[93] To scale the survey up to derive overall market behaviour it is necessary to survey each customer class and estimate the number of customers and likely volumes associated with each class. The estimated numbers in each class is also subject to uncertainty but for larger customers it is expected that the survey would involve total coverage and that the element of uncertainty is limited to whether a potential major user may choose to establish a new plant or not.

In addition to specific customer requirement forecasts a number of market wide forecasts are required.

Market-wide forecasts

Although generally available market growth forecasts could be used, by themselves they do not capture uncertainty associated with them. The following is an example of one approach that could be adopted.

Benchmark economic growth g could be based on official forecasts of real GDP growth but uncertainty could realistically be represented as a near random walk (autoregressive) process about the level chosen. For this example

$$g(t) = 0.03 + u(t)$$
where
$$u(t) = 0.6u(t-1) + e(t) \qquad (6)$$

and e(t) is distributed as N(0, 0.01). i.e. normally distributed with mean zero and standard deviation 0.01.

The price rise for alternative fuels a(t) is assumed to follow a similar process. In this case it is assumed all alternative fuels follow the same price growth but a number of different fuels could have easily been considered. In this example assume

$$a(t) = 0.02 + v(t)$$
where
$$v(t) = 0.4v(t-1) + e(t) \qquad (7)$$

and e(t) is distributed as N(0, 0.01).

Another global variable is the well head gas price G(t). In this example it is assumed it follows the same price path as the alternative fuels

That is $G(t) = G(t-1) \, . \, a(t) \qquad (8)$

For the purpose of this example gas distribution costs are not explicitly modelled and therefore could be thought of as being included with the well-head price of gas G(t).

Table A1.1. Summary of parameter definitions for a company being surveyed

Parameter	Definition
E(t)	Energy demand in period t
x	Ratio of demand to GDP growth
A(t)	Price of alternative energy
a(t)	Increase in A(t) over previous year
K(t)	Measure of gas changeover cost
L	No years for K(t) to fall to zero

93 actually any probability distribution may be contemplated.

Generating the demand scenarios

An example of survey outcomes for 10 customer classes is illustrated below.

Table A1.2. Customer characterisation survey example.

Customer class	Expected number of customers (random)[1]	E(0) Energy demand at time 0 (PJ pa)	X Ratio of demand to GDP growth	A(0) Price of alternative energy at time 0	Initial gas change-over cost K(0) (random)[2]	Remaining life of existing plant L (random)[2]
1	2	10	1.00	10	N(1,0.3)	N(5,2)
2	3	4	0.80	10	N(2,1)	N(5,2)
3	6	2	1.20	10	N(2,1)	N(5,2)
4	11	1	1.00	10	N(2,1)	N(5,2)
5	23	0.5	0.50	10	N(2,1)	N(5,2)
6	45	0.2	1.50	10	N(2,1)	N(5,2)
7	75	0.1	1.00	10	N(2,1)	N(5,2)
8	165	0.05	1.00	10	N(2,1)	N(5,2)
9	550	0.02	1.00	10	N(2,1)	N(5,2)
10	2250	0.005	1.00	10	N(2,1)	N(5,2)

Notes:
1. Expected number of customers is generated from a number distribution with a mean as specified and a standard deviation set equal to 20 per cent of the mean. The sample values are rounded to the nearest whole number.
2. Random value from normal distribution identified in the table cell. For example N(5,2) denotes selection of a random number from a distribution with a mean of 5 and a standard deviation of 2.

To generate demand forecasts based on these parameters the tariff path needs to be specified. In the sample simulations shown below it is assumed that the tariff in year 0 is $1.100 per GJ and escalates on a yearly basis according to a CPI-X rule (CPI=2.5% and X=1%).

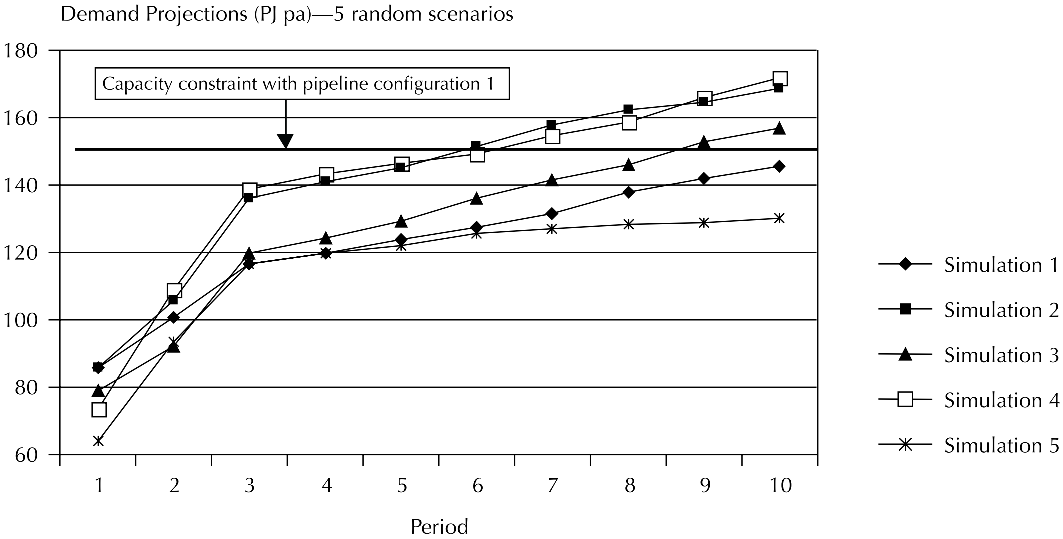
The first five scenarios generated by the parameter assumptions are shown in graph A1.1.

Note that in all five scenarios demand in period one is non zero, that is **some** customers will require gas in the first period of each simulation. However, this is not necessarily the case for individual customers whose changeover costs make an immediate transition to gas uneconomic. The non zero results in the early years indicates that there are always some customer classes for which an immediate transition to gas is worthwhile. The relatively steep take-up in the early years reflects the fairly rapid reduction in the transition related disadvantages of gas. That is the more rapid demand growth in early years is caused by customers switching to gas from other fuel sources as changeover costs diminish. In later years, when most potential customers have made the switch growth relies purely on the growth in energy demand of existing customers.

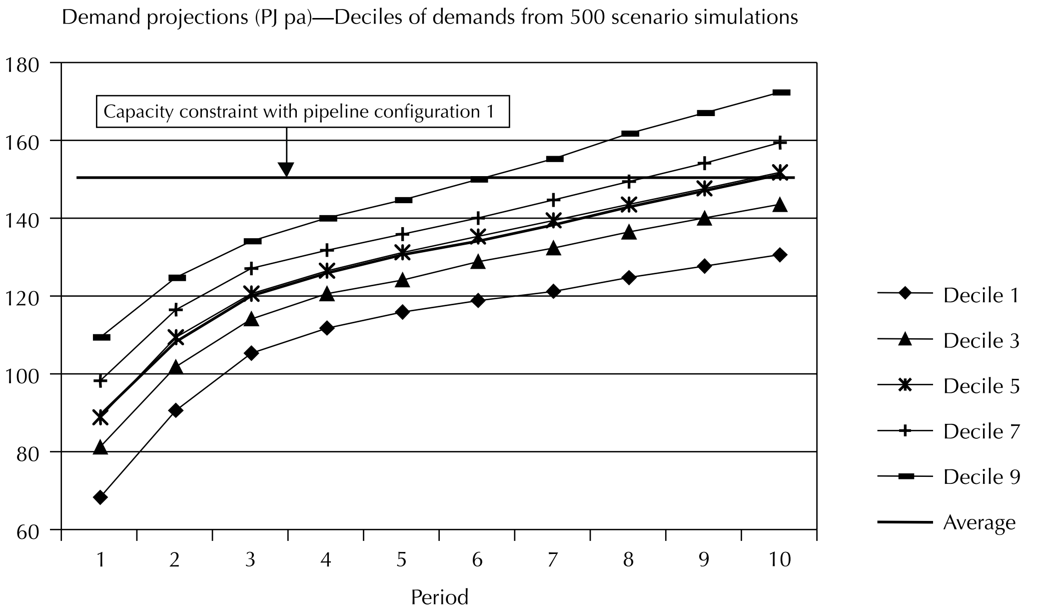
To obtain a fuller appreciation of the spectrum of scenario possibilities significantly more simulations are required. Below the analysis is based on 500 scenario simulations. The range of outcomes is illustrated in graph A1.2 which shows demand levels in each year based on a decile based breakdown of volumes in each year. The values for the 1st, 3rd, 5th, 7th and 9th deciles are chosen as an indicator of the median within each quintile range.

It should be noted that graph A1.2 also plots the average demand scenario over the 500 simulations and that this almost coincides with the plot for the 5th decile of demands simulated (i.e. the median outcome). This suggests that the demands are more or less symmetrically spread either side of the average or expected demand scenario.

Graph A1.1. Demand projection scenarios based on randomised parameter



Graph A1.2. Selected deciles of demand in each year from 500 projection scenarios based on randomised parameter values



The five scenarios graphed represent a summary of demand outcomes and could be used as a basis for further simulations without the need to simulate demand from individual customers. In this summary portfolio of outcomes each scenario presented has equal probability (0.2). Such a simplified approach would be attractive when the complexities of calculating costs and rates of return in conjunction with each demand simulation represents a significant computational burden.

Revenue and rate of return implications

Any developer of a pipeline needs to go one step further before deciding on the feasibility of the project. The cost of building and operating the pipeline needs to be factored into the analysis to observe whether a satisfactory return is available from the project. To illustrate this aspect of the analysis it is assumed that two pipeline configurations are possible each with expansion capacity provided by up to two compressors (see table A1.2).

The returns available from demand generated in any scenario can be linked with a return on equity available with either pipeline configuration. A summary of returns observed from the 500 scenarios is shown in table A1.4. The simulations assume that compressors are installed just in time to meet any projected demand in the year ahead. However, if maximum capacity is exceeded no additional revenue is forthcoming as the additional demand cannot be met. This acts as a cap on the blue sky available from higher demand scenarios, particularly in the case of the smaller pipeline proposal.

Table A1.3. Possible pipeline configurations—capacity and costings

Aspect	Configuration 1	Configuration 2
Pipeline cost	$500m	$600m
Economic life (years)	80	80
Initial capacity (PJ pa)	100	150
Capacity (1 compressor)	130	195
Capacity (2 compressors)	150	225
Cost of compressor	$30m	$33m
Economic life (years)	30	30
Real operating costs pa	$10m	$12m

Table A1.4. Summary of rate of return outcomes from each pipeline configuration (return on equity over 10 years per cent pa)

Demand scenario	Configuration 1	Configuration 2
Average of 500 scenarios	13.81	14.74
Average demand scenario	14.02	14.91
Decile 1 scenario	10.93	11.33
Decile 3 scenario	12.73	13.23
Decile 5 scenario	14.03	14.94
Decile 7 scenario	15.25	16.30
Decile 9 scenario	16.62	18.05
Average of 5 scenarios	13.91	14.77

The average demand scenario is not significantly affected by the capacity constraint and therefore does not capture the negative impact on return from the constraint. In other words the returns from the various scenarios under pipeline configuration 1 reveal that it is not sufficient to merely consider the average demand scenario. Taking the average of the returns estimated for each of the 500 demand simulations offers a better guide to the expected return. In configuration 1 the return from the average scenario is quite a bit higher than the expected return overall even though the demand scenarios are symmetrical about the mean. This is a result of the average demand scenarios not being constrained by pipeline capacity. However, it is clear that in a number of scenarios (see graph 1.2) the capacity will be a constraint on blue sky revenues within the 10 year period being considered in about 20 per cent of the outcomes with pipeline configuration 1.

This conclusion is evident in the returns calculated for configuration 2 when capacity constraints are not a limit on additional business (indeed the second compressor is required in only about 0.25 per cent of the simulations). The average of returns obtained in individual simulations is close to the return expected from the average scenario. Further, the higher returns from the demand corresponding to the 7th and 9th deciles are much higher for configuration 2 and this lends support to the conclusion that the capacity constraint reduces the return expectations with pipeline configuration 1.

It was noted above that the return analysis could be performed using the summary five decile scenarios graphed above. Because these include scenarios where the capacity constraint bites, the asymmetry effect is reflected in the average of returns from the five scenarios. Each of the five scenarios represents the median of a range of outcomes with equal probability. Therefore the unweighted average of returns provides an unbiased estimate of the expected value of returns over all outcomes. This average is close to the result obtained with 500 simulations and illustrates the computational saving of working with the summary scenarios.

Summary

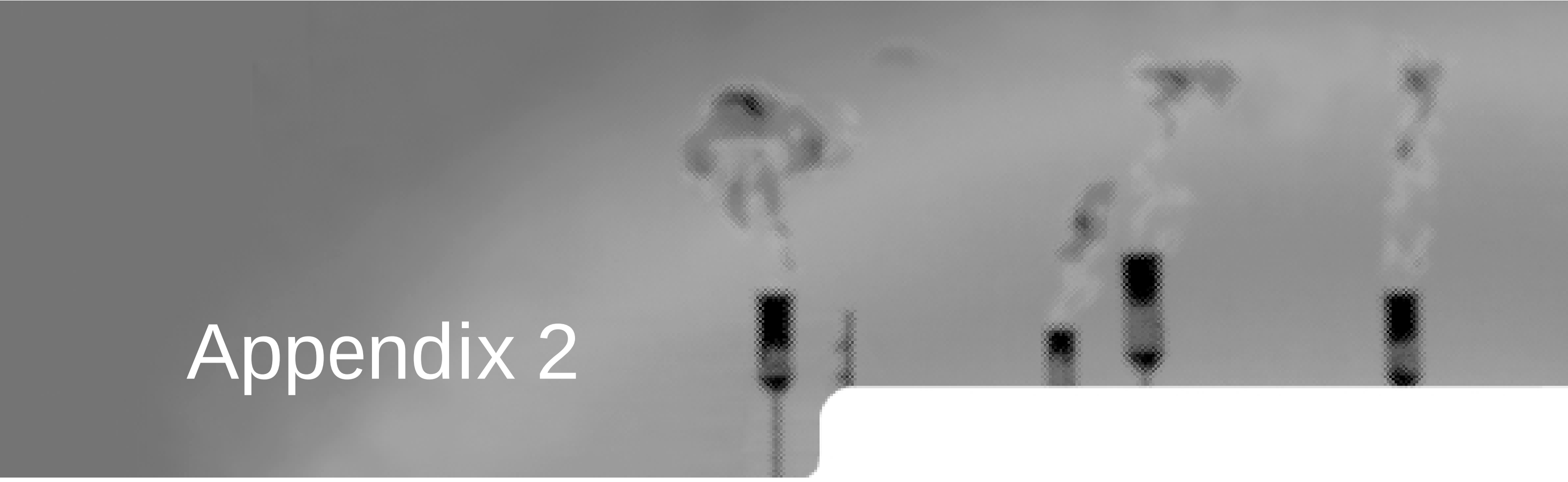
Significantly, the expected return from configuration 1 is much lower than for configuration 2, suggesting that it will be more cost effective to build the larger pipeline despite the higher costs and the fact that in configuration 2 the pipeline is not expected to be used to its full capacity in many instances.

The example of capacity constraint illustrates the value of scenario simulation when there are issues of asymmetry to deal with. Where there is an asymmetry in potential revenues about a normal or median outcome the returns calculated on the assumption of the median demand outcome offers a poor guide as to the prospective return that may be expected. This is true whether the pipeline is regulated or not. However, if there is a concern that the regulatory framework itself gives rise to the asymmetry the approach offers a mechanism for dealing with it. This particular issue is covered further in appendix 3.

Finally, table A1.4 shows that the actual outcome may be significantly higher or lower than the regulatory rate of return with an achievable return on equity of over 18.05 per cent being consistent with an average expected return of 14.77 per cent.[94]

As a final step in the use of such simulations for regulatory purposes it is necessary to find the reference tariff that provides an expected rate of return equal to the CAPM based regulatory rate of return. This is found by a systematic adjustment of the initial tariff setting or the X factor so that the desired return on equity is the result of the average return on equity over a large number of simulations with the selected pipeline configuration.

[94] Some of the higher demand scenarios gave rise to an achieved return on equity over 19.0 per cent.



Appendix 2

Example of an adjustment to the initial capital base to reflect actual costs and the effect on reference tariffs

The ACCC considers the inclusion of a symmetric adjustment mechanism can accommodate any material variance between the forecast and final cost of the initial capital base (ICB); facilitate certainty regarding how under or over recovery of costs can be remedied; avoid potential discontinuities in the reference tariff price path to avoid volatility in tariffs; and provide certainty for users.

Clearly a range of appropriate adjustment mechanisms are possible and the optimal approach from a service provider's perspective is likely to depend on its own unique circumstances. The following illustrative examples set out a number of mechanisms that could be used.

Suppose that the pipeline is forecast to comprise two classes of asset A and B. A has an expected life of 50 years and B has an expected life of 20 years. Forecast costs for each class of asset is $100m each. Assume at the end of year two actual costs become known and expenditure on A is $120m and on B is $90m.

Reference tariffs would have been initially formed on the basis of the $100m forecast costs. The building block approach is used to establish the target revenues to derive the reference tariffs. See table A2.1.

- The WACC is assumed set at 8.00 per cent.

If the regulator had perfect foresight it would have used actual numbers for capex and obtained revenues as shown in table A2.2.

Perfect foresight is not available but at the beginning of year two or at the next convenient reset opportunity, tariffs and the regulatory asset base roll forward calculated can be adjusted in a mechanistic way to fully accommodate the error in capital expenditure estimates.

Table A2.1. Tariffs based on forecast capex costs

Regulatory asset base roll forward

Period	1	2	3	4	5	c/f RAB to next reset
Asset value at start of period						
Asset A ($m)	100.00	98.00	96.00	94.00	92.00	90.00
Asset B ($m)	100.00	95.00	90.00	85.00	80.00	75.00
Total RAB	200.00	193.00	186.00	179.00	172.00	165.00
Depreciation during period						
Depreciation on asset A	2.00	2.00	2.00	2.00	2.00	
Depreciation on asset B	5.00	5.00	5.00	5.00	5.00	
Total depreciation	7.00	7.00	7.00	7.00	7.00	
Building block components						
Return on capital (WACC 8%)	16.00	15.44	14.88	14.32	13.76	
Depreciation	7.00	7.00	7.00	7.00	7.00	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	26.88	26.32	25.76	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.840	0.798	0.758	
Initial expected net cash flows	23.000	22.440	21.880	21.320	20.760	178.2[1]
NPV of cash flows[1]	$200.00					

Note: 1. The NPV of net cash flows is valued at the start of period 1 and includes the value of the carried forward value of the RAB ($165m) at the end of period 5 (this value is shown in column 6 adjusted up to accommodate discounting between periods 5 and 6). A regulatory framework giving a prospective rate of return must have the NPV of net cash flows equal to the initial cost of the assets.

Table A2.2. Tariffs based on actual capex costs

Regulatory asset base roll forward

Period	1	2	3	4	5	c/f RAB to next reset
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
Total RAB	210.00	203.10	196.20	189.30	182.40	175.50
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Total depreciation	6.90	6.90	6.90	6.90	6.90	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.70	15.14	14.59	
Depreciation	6.90	6.90	6.90	6.90	6.90	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.70	28.15	27.60	27.04	26.49	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.957	0.908	0.862	0.820	0.779	
Net over-recovery using forecast figures in table A 2.1	-0.700	-0.708	-0.716	-0.724	-0.732	
Expected cash flows under option	23.700	23.148	22.596	22.044	21.492	189.54
NPV of cash flows	$210.00					

It is not necessary to track the errors in the depreciation building blocks and for the return on capital components to achieve this. All that is required is to observe the difference in revenues calculated under the two different sets of capex. The updated revenue estimates may be above or below those calculated initially. Where it is above, the initial revenue estimate is inadequate to provide both the necessary return on capital and provide for the planned path of depreciation. It is convenient to assume that all the shortfall is accounted for by a temporary stalling in the return of capital. Similarly, where updated revenues are below the initial estimates it is assumed there has been an excess over the planned rate of return of capital.

Under this interpretation all that needs to be done to re-validate the regulatory accounts is to explicitly recognise the accumulated excess/shortfall in the regulatory accounts and make adjustments to ensure that the integrity of the regulatory asset base roll forward is preserved.

This may be done in a number of ways that preserve the expected rate of return on investment calculated as appropriate in the initial regulatory decision.

Option 1. Allow an immediate change in tariffs to follow the price path calculated based on the actual capex data when it is available. This approach requires an adjustment of the regulatory asset base at the next regulatory reset to reflect the excess/shortfall in the return of capital carried forward and the potential return on that portion of capital. There is some discretion in deciding which class of assets should be subjected to the accommodating adjustment; however, an apportionment in proportion to the written down asset value would seem fairly reasonable.[95] The adjustments relevant to the examples above are shown in table A2.3. It should be noted that the NPV of the cash-flows following these adjustments equates to the initial capital costs confirming consistency with the regulatory rate of return as an expected outcome.

Option 2. Allow the initial forecast price path to continue until the next regulatory reset. This is likely to lead to an increase in the excess/shortfall capital return. The principles used are the same as option 1 and require an adjustment to the carried forward value of the RAB. If the price changes are minor this may be the simpler approach. The main shortcoming of deferring any adjustment is that there may be a more significant tariff adjustment required in transition to the next regulatory period.

Table A2.3. Option 1—Adjustments to remedy errors in forecast capex costs (assuming actual capex costs become known at end of period 2)

Period	1	2	3	4	5	RAB adjustment
Extra depreciation	-0.70	-0.71	0.00	0.00	0.00	0.00
Accumulated extra depreciation	-0.70	-1.41	-1.41	-1.41	-1.41	-1.41
Accum depr + return on it	-0.70	-1.46	-1.58	-1.71	-1.84	-1.84
Actual cost carried forward RAB						175.50
Modified carried forward RAB						177.34
Expected cash flows under option	23.000	22.440	22.596	22.044	21.492	191.5318
NPV of cash flows	$210.00					

Table A2.4. Option 2—Adjustments to remedy errors in forecast capex costs (although actual capex costs become known at end of period 2 forecast price path is used until next reset)

Period	1	2	3	4	5	RAB adjustment
Extra depreciation	-0.70	-0.71	-0.72	-0.72	-0.73	0.00
Accumulated extra depreciation	-0.70	-1.41	-2.12	-2.85	-3.58	-3.58
Accum depr + return on it	-0.70	-1.46	-2.30	-3.20	-4.19	-4.19
Forecast carried forward RAB						175.50
Modified carried forward RAB						179.69
Expected cash flows under option	23.000	22.440	21.880	21.320	20.760	194.0687
NPV of cash flows	$210.00					

95 Generally, assets within a regulatory framework are classified by function of the assets and the rate of depreciation (or economic life) assigned to those assets. In this context it is sufficient to classify assets according to their planned depreciation profile (or by expected economic life).

Option 3. In principle it is possible to make an overcompensating adjustment in a move to the new price path so that by the end of the regulatory period any excess/shortfall capital return is reduced to zero. This avoids the need to make a further adjustment to the RAB carry forward value. These calculations are shown in table A2.5. The calculations recognise that the net over-recovery of depreciation needs to be undone over the remaining periods of the access arrangement. Such an approach is not generally favoured for those scenarios where the tariff path has relied on smoothing or where volumes are changing rapidly as the revenue implications are complex and the necessary tariff adjustments much more difficult to assess.

Table A2.5 . Adjustments required under option 3 —recalculating price path to accommodate forecast error to date and creating the carried forward RAB value consistent with knowing actual costs from the start (assuming actual capex costs become known at end of period 2)

Regulatory asset base roll forward

Period	1	2	3	4	5	CF RAB to next reset
Net over recovery of revenue	-0.7	-0.7				
Cumulative over-recovery at start of period	0.0	-0.7	-1.5	-1.6	-1.7	-1.8
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
RAB adjustment	0.00	0.00	1.46	0.98	0.49	0.00
Total RAB	210.00	203.10	197.66	190.28	182.89	175.50
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Notional extra depreciation	-0.70	-0.71	0.49	0.49	0.49	
Total depreciation	6.20	6.19	7.39	7.39	7.39	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.81	15.22	14.63	
Depreciation	6.20	6.19	7.39	7.39	7.39	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	28.20	27.61	27.02	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.881	0.837	0.795	
Expected cash flows under option	23.000	22.440	23.201	22.610	22.019	189.54
NPV of cash flows	$210.00					

Note: Approximate values can be obtained by dividing the accumulated extra depreciation to date by the number of periods left. However, this ignores the return on that component of capital. In practice it is a simple matter to use the ‘goal seek’ values for depreciation which restore the ARB based on actual costs going into the next reset period.

Option 4. Finally, it is possible to acknowledge the error in revenues posed by the capex forecasts and recalculate the tariffs going forward accordingly. This is similar to option 3 in that there is a jump to a new price path. But because of any net over recovery of depreciation to date is not explicitly reversed the carried forward asset value is also modified. Despite the modifications on these two fronts the approach has appeal in that it best reflects an immediate recognition of the previous error and recalculates all future tariffs and asset values taking that error into account.

The relevant calculations are shown in table A2.6.

It should be noted that the validity of each option is confirmed by calculating the NPV of the resultant cash flows and the residual asset value carried forward to the next reset using the WACC as the discount rate. Under each option, for adjustment to take account of the error in capex forecast, the NPV should equal the actual cost of the assets at commencement of operations (start of period 1). Each of the four options outlined above are consistent with the building block approach and are confirmed by its NPV equivalence. Accordingly, from a financial perspective, a service provider should be indifferent between the four options.

Table A2.6. Adjustments required under option 4—recalculating price path to accommodate forecast error to date (assuming actual capex costs become known at end of period 2)

Regulatory asset base roll forward

Period	1	2	3	4	5	CF RAB to next reset
Net over recovery of revenue	-0.7	-0.7				
Cumulative over-recovery at start of period	0.0	-0.7	-1.5	-1.6	-1.7	-1.8
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
Cumulative RAB adjustment	0.00	0.00	1.46	1.46	1.46	1.46
Total RAB	210.00	203.10	197.66	190.76	183.86	176.96
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Notional extra depreciation	-0.70	-0.71				
Total depreciation	6.20	6.19	6.90	6.90	6.90	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.81	15.26	14.71	
Depreciation	6.20	6.19	6.90	6.90	6.90	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	27.71	27.16	26.61	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.866	0.823	0.783	
Expected cash flows under option	23.000	22.440	22.713	22.161	21.609	191.12
NPV of cash flows	$210.00					

Q&A

Question 1. Should the existence of foundation contracts alter the approach taken to these adjustments.

Answer 1. No. The tariffs in foundation contracts have been negotiated and are normally legally binding. They may include rise and fall clauses to accommodate unexpected changes in costs but these do not impinge on the regulatory calculations.[96]

Question 2. Suppose volumes and consequently revenues are quite different from those forecast as part of the regulatory decision. Does this alter the calculations that are required to adjust for updates in capital costs?

Answer 2. No. No adjustment would be made in such cases if there were no error in forecast capital costs. A shortfall or excess of revenues in such cases is part of incentive mechanism within the regulatory framework for the service provider to expand the market for its services. Those incentives must be preserved within the adjustment mechanism so it is only the target revenues emerging from the regulatory calculations that need to be factored into the adjustment.

[96] Refer code section 2.25 and 6.15(e)

Appendix 3

Example of benefit sharing when demand exceeds a pre-set threshold

This appendix builds on the framework demonstrated in appendix one in relation to determining expected demand and revenues in the face of uncertainty. In the event that an upside or downside outcome was realised during a regulatory period that was extreme or outside the range of outcomes reflected in the simulations, the regulator is required to consider sharing mechanisms.

This appendix provides an illustrative example of how such a benefit sharing mechanism may be designed in order to provide ex-ante certainty regarding its operation and effect on revenues subsequently realised beyond a certain point.

The framework in appendix one depended on assigning probabilities to the range of feasible outcomes. In general, there is no way of knowing whether the scenarios developed are free from bias and an observed actual demand outcome is a genuine random event consistent with the scenarios postulated. An exception to this is when an actual outcome is outside the range of the probabilistic scenarios considered. Such an outcome may or may not be a result of misrepresentation of likely scenarios. It does not matter whether the divergence is above or below the range of forecasts made. In either case, it is clear that the basis for establishing the reference tariffs was flawed and a reassessment warranted. However, such a reassessment poses a problem of principle linked to the need to use expectations at the time of financial close.

If demand turns out to be worse than envisaged in any of the scenarios there is already a mechanism available to reconsider regulated revenues since the code allows the service provider to seek a review at any time. However, this scenario too poses the same conflict of principle in that the risk based framework would be put aside.

If the outcome involves demand higher than any scenarios considered in establishing reference tariffs there is no mechanism by which the regulator can seek a review. A reset of tariffs based on actual blue sky demand 'ex post' is considered detrimental to incentives and is the main reason for establishing the framework such as that described in appendix 1.

Therefore, the regulatory framework needs to be able to cater for unexpected demand aberrations at the time of the initial assessment. This is because it is inconceivable that any probabilistic scenarios postulated in response to the deviant outcome could be viewed as an ex-ante expectation. Hence the concept of maintaining revenues on the basis of expectations held at the time of financial close would be lost. To cope with the situation a benefit sharing mechanism is proposed that enables customers to receive some of the benefits of greater than expected demand. To handle the symmetrical issue of demand short fall a parallel mechanism could also be proposed to allow the service provider to regain lost ground. In the case of high demand realisations, this could be achieved by reducing the proposed reference tariffs when demand exceeds certain pre-set thresholds.[97] This will reduce some of the blue sky that may have been obtainable by the service provider, but if sharing is an anticipated possibility it the 'ex ante' net value of that blue sky

A benefit of such a mechanism is to reduce the incentive for a service provider to distort its

[97] While this can be thought of as tariff moderation the benefit sharing may be achieved in practice by rebates or treating the excess return as a return of capital that will lead to a reduction in the value of the carried forward asset base at the next review.

view of anticipated demand outcomes. This is achieved because the benefit sharing mechanism is less likely to be triggered when forecasts are accurate. In this way the service provider gains greater certainty of expected returns in such circumstances by truthful revelation of demand scenarios. Such sharing is to occur in any period in which demand exceeds the preset threshold. A similar mechanism for sharing can be specified when there are shortfalls in demand.

A suggested mechanism

The threshold for sharing is derived from the scenarios used to establish the reference tariffs. The upper threshold demand trigger in period t, TU(t) beyond which sharing is to occur, is set equal to the average demand Dav(t) plus the standard deviation SD(t) of demand outcomes forecast for period t.

$$TU(t) = Dav(t) + SD(t) \qquad (1)$$

Beyond this level of demand the extra revenues achieved are to be shared with users through a rebate mechanism or a reduction in tariffs.

A low threshold demand trigger TL(t) can be similarly defined.

$$TL(t) = Dav(t) - SD(t) \qquad (2)$$

Below this level of demand the shortfall in revenues achieved are to be partially recovered in future tariffs.

The sharing could be on a 50/50 basis but a sliding scale could also be used. Such a rebate formula is given by:

$$Rebate(t) = (0.5 \times (D(t) — TU(t))/ D(t)) \times Revenue \qquad (3)$$

where D(t) is actual demand in period t.

Note that in this instance Rebate(t) represents a percentage of the revenue from demand serviced in year t and which needs to be rebated to customers.

A simple example

Suppose three scenarios are proposed initially each with equal probability. Each scenario starts with demand at 100 PJ pa in period 1. But in

scenario 1 demand grows at 2 PJ pa
ie D1(t) = 100 + 2t PJ;

scenario 2 demand grows at 4 PJ pa
ie D2(t) = 100 + 4t PJ; and

scenario 3 demand grows at 6 PJ pa
ie D3(t) = 100 + 6t PJ.

Suppose for simplicity the reference tariff will be set at a constant price per GJ. The average scenario is scenario 2 and the standard deviation in period t is 1.6t PJ.

thus the upper trigger threshold demand path is given by:

$$TU(t) = 100 + 4t + 1.6t \qquad (4)$$

And the lower trigger threshold by:

$$TL(t) = 100 + 4t — 1.6t \qquad (5)$$

As shown in graph A3.1 the lower and upper thresholds are exceeded in scenarios 1 and 3 respectively. That is there will be an element of revenue sharing in these scenarios even though they are represented in the portfolio of possible scenarios postulated. This is not considered a problem since the revenue sharing mechanism is also integrated into the reference tariff framework described in appendix 1. The modification of the revenues is taken into account when establishing the reference tariff, which may be somewhat higher or lower than it otherwise would have been. In this case the symmetry in the demand scenarios means that the middle or average scenarios would give rise to the same reference tariff as using the probabilistic scenarios. However, in the example below part of this symmetry is lost because demand exceeds pipeline capacity in scenario 3 in periods 9 and 10.

Assumptions:

Target WACC is set at 8.00 per cent;

The initial capital cost is $800m;

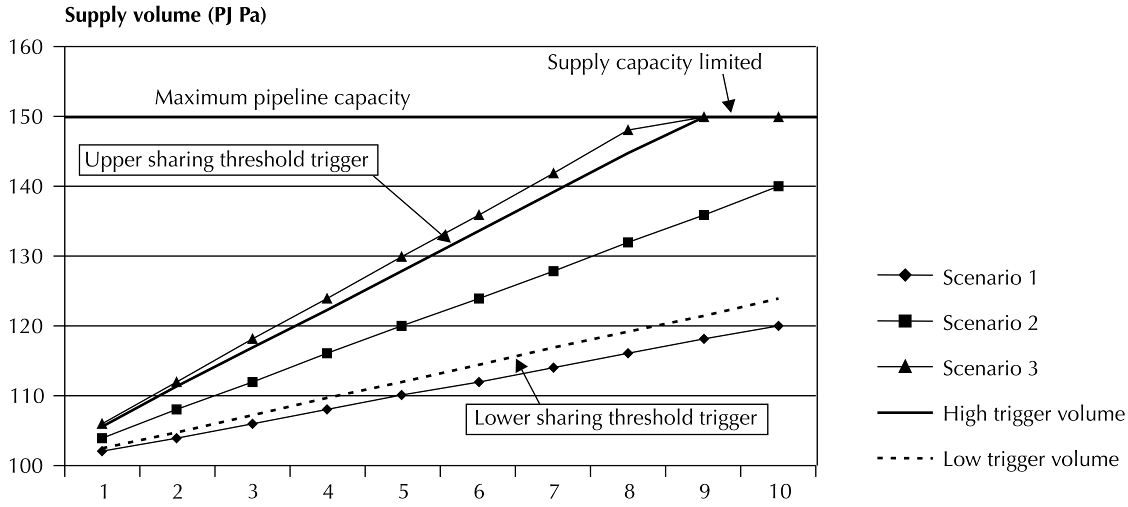
The residual asset value after 10 years is $700m;

Maximum pipeline capacity 150 PJ per year; and

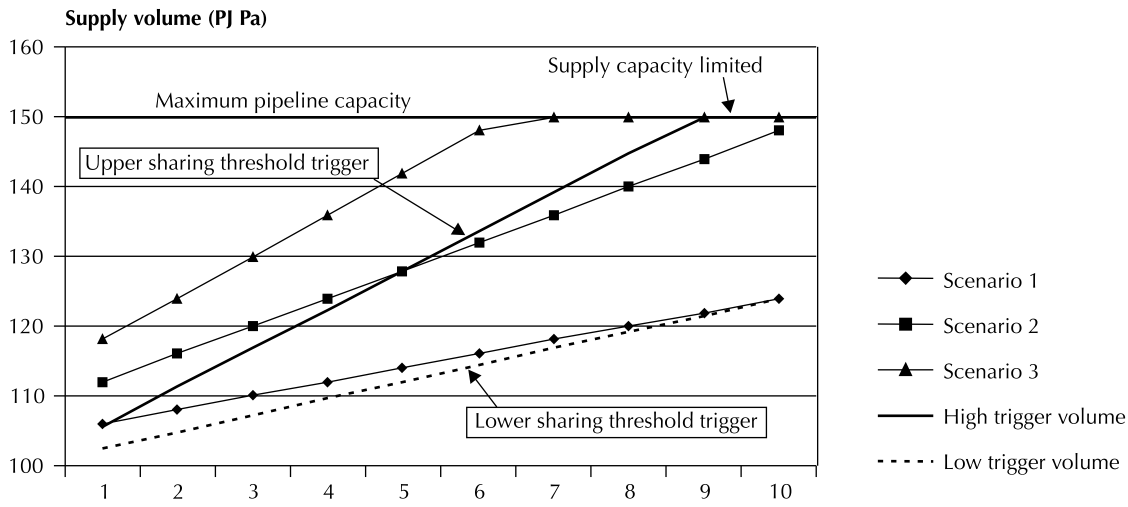
O&M costs are a constant $25m per year.

Cash flow modelling shows that the reference tariff consistent with these assumptions and the assumed level (50 per cent) of benefit sharing $0.8047 per gigajoule. With different sharing levels the reference tariff may vary but because of the symmetry in demand scenarios the variations in this example as shown in graph A3.1 below are minor. With zero sharing the reference tariff would be $0.8040 per gigajoule and with 100 per cent sharing $0.8054 per gigajoule.

Graph A3.1. Demand volumes forecast under the three scenarios and high and low trigger volumes for revenue sharing



Graph A3.2. Demand volumes under the three corresponding scenarios but with demand brought forward by two periods, original high and low trigger volumes for revenue sharing are also shown



Under scenarios 1 (low demand) and 3 (high demand) a mild amount of revenue sharing is already occurring. As shown in graph A3.1 and table A3.1, this is reflected in the achieved rate of return with sharing featured. Graph A3.2 illustrates what could happen in the future if demand increases more than expected (in this case illustrated by bringing demand forward by two periods. The extent by which actual demand exceeds the trigger volume line indicates the amount of sharing. For example under a 50 per cent sharing mechanism the revenues achieved in a year would be as if demand was midway between the actual demand and the trigger value. A similar picture of demand shortfall is produced by assuming demand growth is delayed by two periods.

Table A3.1 shows the actual return that would be achieved under each outcome and sharing assumption.

Table A3.1. Impact of revenue sharing on achievable returns under alternative scenarios

Ex ante expectations of achievable rate of return on assets					
Percent sharing %	**0**	**25**	**50**	**75**	**100**
Ex ante expectations of return on assets					
Scenario 1	7.03%	7.08%	7.13%	7.17%	7.22%
Scenario 2	8.04%	8.04%	8.03%	8.03%	8.02%
Scenario 3	8.92%	8.88%	8.84%	8.80%	8.76%
Average return (%)	8.00%	8.00%	8.00%	8.00%	8.00%
Reference tariff ($/GJ)	0.8054	0.8051	0.8047	0.8044	0.8040
Rate of return achievable on assets with increased demand with above reference tariffs (brought forward two periods earlier than expected)					
Percent sharing %	**0**	**25**	**50**	**75**	**100**
Achievable rates of return on assets					
Scenario 1	7.43%	7.43%	7.43%	7.43%	7.43%
Scenario 2	8.83%	8.78%	8.73%	8.67%	8.62%
Scenario 3	9.84%	9.56%	9.30%	9.03%	8.76%
Average return (%)	8.70%	8.59%	8.48%	8.38%	8.27%
Rate of return achievable on assets with reduced demand with above reference tariffs (market growth delayed by two periods)					
Percent sharing	**0**	**25**	**50**	**75**	**100**
Achievable rates of return on assets					
Scenario 1	6.63%	6.78%	6.92%	7.07%	7.22%
Scenario 2	7.26%	7.26%	7.26%	7.26%	7.26%
Scenario 3	7.88%	7.88%	7.88%	7.88%	7.88%
Average return	7.26%	7.31%	7.35%	7.40%	7.45%

Other points to note from the simulations are as follows.

As expected, the effect of the sharing is to bring the returns under the extreme demand scenarios closer to the average expectation.

Regardless of the proportion of sharing proposed it is always possible to find the tariff that provides an ex ante expectation of the required 8 per cent return on assets.

This tariff decreases slightly with the level of sharing assumed because the sharing moderates the downside scenario more than the upside that is capped by the capacity constraint.

Without sharing (i.e. sharing of 0 per cent) the impact of an unexpected surge in demand is to increase achieved revenues and achieved return on assets. Similarly, a shortfall in demand reduces returns.

The increase in achieved returns is moderated by the impact of the sharing mechanism with the extent of moderation depending on the level of sharing specified. Returns are similarly stabilised when demand falls.

Where the sharing mechanism is not triggered under a scenario there is no change in return from what would be observed in the absence of benefit sharing.

At the extreme in scenario 3 when the trigger was already operating without the demand surge, the impact of 100 per cent sharing is to prevent any additional returns being achieved by the service provider. A similar effect is observed in scenario 1 in conjunction with the shortfall in demand expectations (the 100 per cent sharing example is included as illustration only and is not a proposed sharing setting).

- In all cases (apart from the last) the service provider retains an incentive to pursue market expansion as a means of increasing profits.

This example does not specify how the benefit sharing takes place. Different approaches may be applicable in different circumstances. The following are examples.

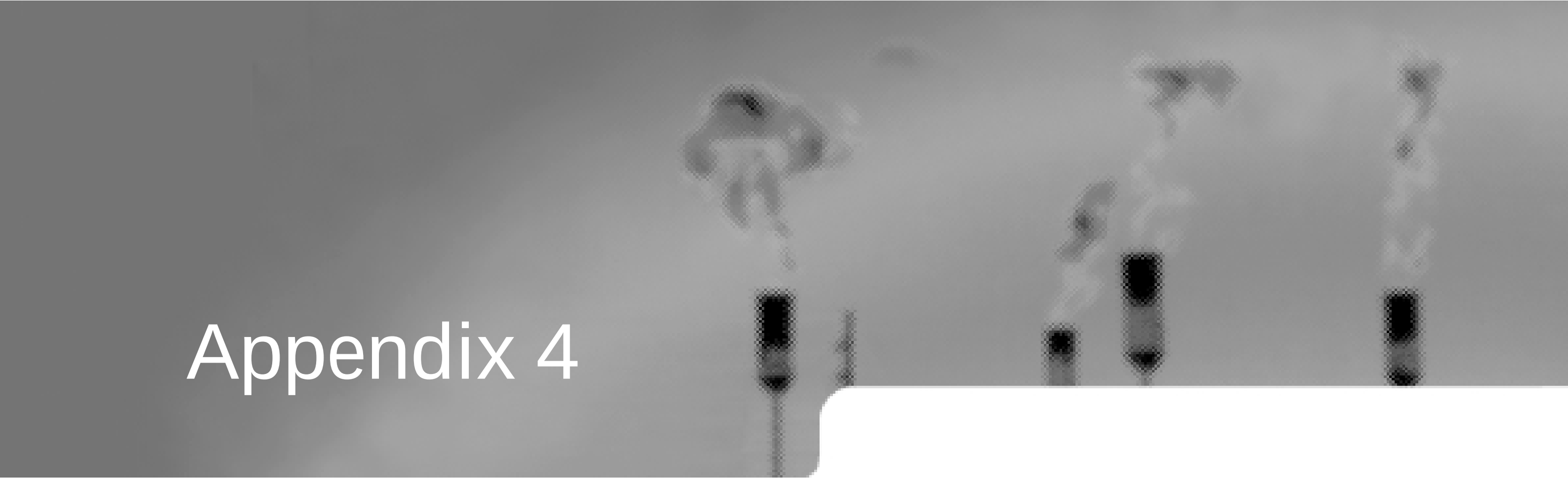
- Where additional demand (or demand shortfalls) can be anticipated in advance of annual price adjustments for CPI the actual tariff for the year ahead could be reduced/ increased by the amount that reduces/ increases revenues by the amount of the sharing.

- Where demand cannot readily be anticipated the benefits could be shared by providing appropriate rebates to customers at the end of the accounting year.

- Where it is difficult to anticipate demand, and where it is difficult to arrange end of year balancing arrangements or rebates (e.g. it would be difficult to extract additional charges from customers at the end of the year), an adjustment could be made to the residual value of the asset base to reflect the over or under recovery of revenues. When the residual is augmented, the revenues are subsequently recovered in future regulatory periods after the next regulatory review.[98] When the residual value is reduced (customers paid too much) customers receive reduced tariffs in the future as compensation.

The choice of mechanism is more a matter of practicality rather than being a matter of regulatory principle.

98 This is similar to the economic depreciation approach proposed for the Central West Pipeline where loss or under recovery of revenues because of low demand in early years is compensated by capital appreciation of the regulatory asset base to allow eventual recovery when the market matures.



Appendix 4

Summary of consultancies

Macquarie Bank Limited

'Issues for debt and equity providers in assessing greenfields gas pipelines'

Introduction

Macquarie Bank Limited (MBL) was engaged to advise the ACCC on what information would generally be required by debt and equity providers in assessing a greenfields natural gas transmission pipeline project. The report describes MBL's opinion, based on its experience of the Australian energy market.

Key findings

Debt holders require information on all the risks associated with the project. This enables the debt holder to assess the risk profile of the project and determine the amount, and cost, of debt that can be made available to the project. Equity holders also assess the risk profile of the project to determine their capital contribution, its structure and their required rate of return.

A single purpose company or trust is often established as the 'project vehicle' to undertake a pipeline project. This has the benefit of quarantining the project risks from the parent business. The project vehicle will then seek to minimise its cost of capital by maximising the relatively less expensive debt component. It should be noted that the source of funds from the domestic banking market is generally limited to $1 billion. Funds will also be limited by each bank's exposure to the project and the industry as a whole. Funding from the capital markets can be more cost effectively used once projects have moved from the construction phase to the operation phase. In addition, if a business is able to obtain an investment grade credit rating from a recognised agency and meets the credit criteria of the monoline insurers then it may be able to utilise 'credit wrapping'.

MBL advises that equity participants of a project generally determine their contribution to the business' capital with regard to their required rate of return for an investment with the specific risk profile and the time horizon for the investment. An equity holder generally seeks to maximise the nominal after-tax return from the project's cashflows. While equity holders use a similar approach to risk assessment as debt providers, they may be willing to assume a higher risk and make more aggressive assumptions.

MBL identified 14 specific risk categories that would be considered in a debt financing assessment. These included the following.

- **Construction risk**. Large pipelines are very sensitive to construction risk as they have a considerable period when revenue is not earned but borrowings are accruing interest. Debt providers seek to ensure that contractual arrangements allocate responsibilities and risks appropriately over this time.

- **Market and revenue risk**. While debt providers consider the extent that a pipeline has foundation contracts established in forming a view on the debt available for a project, equity providers are more likely to take the risk that the pipeline's market will not develop as predicted. This risk increases with the greater proportion of capacity that is uncontracted.

- **Interest rate and inflation**. Debt providers require pipeline companies to use interest rate hedges to reduce the extent of risk and improve cashflow certainty. If debt providers consider that a regulator will redetermine the business' return at the end of the regulatory period then they will require interest rates to be hedged to this date.

- **Regulatory risk**. In considering the cashflows of the new pipeline, debt providers will form their own view on whether the pipeline will be regulated and the nature of the regulatory framework. This view is formed with reference to (amongst other things) previous regulatory decisions in Australia for a variety of businesses. If the regulatory regime is clear and a high level of confidence can be established regarding the cashflows, including the regulator's assessment of the forecasts, then the risk profile of the business will decrease.

In assessing the various categories of risk, financiers may rely upon expert advice from a range of independent consultants, for example to provide assistance in developing forecasts in regard to the regulatory price paths and the supply and demand for gas. Debt providers may rely upon an expert engaged by a service provider or may appoint their own. They may also require independent certification of construction costs and operating and maintenance and capital expenditure forecasts. In some instances debt providers have in-house expertise. Reports will also be required from independent parties concerning the accounting, tax and legal aspects of the project.

Any issues identified by the consultants will be discussed by the debt providers with equity providers and the results will be incorporated into the debt providers financial model and/or the terms and conditions of the debt facility. All the required experts' reports must be specifically addressed to each debt provider. The debt providers will be relying on the reports for their lending decisions and must be able to have legal recourse to the expert for incorrect information.

Davis and Handley

'Cost of capital for greenfields investments in pipelines'

Introduction

Kevin Davis and John Handley[99] prepared a report for the ACCC that considered the appropriate determination of the cost of capital for greenfields investments in gas transmission pipelines. Specific questions to be addressed at the request of the ACCC included:

1. Whether the CAPM is an appropriate framework for assessing the WACC facing a greenfields pipeline.

2. How should risks that are specific to the project be recognised and compensated? For example, the level of return that may accrue to a greenfields pipeline is more uncertain than the returns to a mature pipeline owing to variation in financial parameters during development and construction (such as exchange rates), construction cost variability, operating cost variability (including teething problems) and demand uncertainty (beyond foundation contracts).

3. Whether the CAPM should be augmented to account for the specific risks facing a greenfields pipeline. Specifically, is it appropriate to inflate the beta and, if so, over what period should the inflated beta operate.

4. Whether it is appropriate to utilise a single beta for the pipeline industry as a whole, or whether separate betas should be developed for mature and greenfields pipelines. Is there a case for separating cash flow streams (for example, foundation contracts and speculative demand) and applying different WACCs to each.

[99] Kevin Davis is Commonwealth Bank Group Chair of Finance, Department of Finance, The University of Melbourne. John Handley is senior lecturer, Department of Finance, The University of Melbourne.

5. Subject to the views regarding 1 to 4 above, does a CAPM approach to determining WACC and compensating specific risks in cash flows provide adequate compensation for potential downside risks.

Key findings

Davis and Handley conclude that the CAPM model is an appropriate framework for assessing the appropriate WACC facing a greenfields pipeline project. Noting that while there are a number of alternative approaches to the CAPM framework'none of the alternative approaches have surpassed the CAPM in popularity or use in practice' at this time.

Project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost. Provided that the capital base concept adopted for use in regulatory price determination reflects the cost of such risk transfer, or that the cash flows required to insure or hedge such risks are reflected in operating costs, no further adjustment for risk would appear to be warranted.

Specific, that is non-systematic, risks associated with a greenfields pipeline should not lead to an adjustment of beta—which is intended to reflect systematic risks only. Any such adjustment would be ad hoc and could lead to significant biases.

Davis and Handley note the issues involved in determining an appropriate beta for the purposes of regulating an asset. The suggestion that the beta for greenfields pipelines should be higher than the beta used for established pipelines is considered. In the absence of regulation the authors note there are some grounds for believing that the systematic risk of a greenfields pipeline may be somewhat higher than that of a mature pipeline. The authors suggest that the most significant factor is the long time frame over which cash flows are expected (that is, the cash flows are distant). However the authors also note that the regulatory approach to access pricing (eg redetermining access prices periodically; loss carry forward provisions; and the requirement of the code to use the actual construction costs of a new pipeline as the initial capital base) and the arrangements contained in foundation contracts may reduce this effect.

While it is, in principle, possible to decompose cash flow streams into foundation contracts and non-contract components with different risk characteristics, the practical problems of applying such an approach appear to make it infeasible.

Time lags are involved in construction before cash inflows are realised, and project viability requires that those outlays should be compounded at the required rate of return in determining the cost base of the project.[100]

Finally, the authors stressed that access prices derived on the basis of applying a required rate of return to an accounting asset base (at some date 2), conditional on an assumed level of future output which is different to that expected at the time the investment was made (date 1), are not necessarily compatible with providing appropriate signals for investment. If it is possible that the investment will ex-post (that is, at date 2) have a negative NPV resulting from low demand, and that access will only be sought in cases where demand is high, it is necessary that in that latter (high demand) case the ex-post (date 2) NPV will need to be positive if the ex-ante (date 1) NPV is to be zero.

Davis and Handley suggest one potential solution to this problem. That is, bring forward the coverage or access determination date so that it occurs early in the project appraisal and development or construction stage rather than after project success has been observed.

[100] For example, if a project involves an outlay of $1 at date 0, has a required rate of return of r, and generates no cash flows until date 2, the required cash inflow at date 2 is $1(1+r)2 if the project is to have a zero NPV. If target cash flows at date 2 are to be determined at date 1, the appropriate capital base for use at that date is $1(1+r).

National Economic Research Associates (NERA)

Foundation contracts and 'greenfields' gas pipeline developments:
experience from the US and other jurisdictions

Introduction

NERA was engaged to prepare a report on the role of foundation contracts in new gas pipeline developments in various relevant jurisdictions.

The report was required to address the following.

1. Typical foundation contracts established in overseas jurisdictions. This analysis drew primarily on experience in the United States, and to a lesser extent, experiences in other jurisdictions such as Singapore, Mexico, Argentina, UK etc.

2. Typical construct of a foundation contract. For example, usual terms and conditions, pricing formulae etc.

3. What is the normal relationship between foundation contracts and pipeline capacity (initial and potential) to justify the construction of the pipeline.

4. The incidence of most favoured nation (MFN) clauses in foundation contracts and common variants.

5. The incidence of provisions for blue sky sharing in foundation contracts. Description of typical benefit sharing mechanisms employed in foundation contracts.

6. Extent of regulatory oversight of foundation contracts including criteria employed by FERC to determine whether greenfields gas pipelines should be regulated or unregulated. Description of the nature of regulation applied to greenfields pipelines by FERC.

7. Use of market based tariffs in establishing foundation contracts (for both regulated and unregulated pipelines) and as a basis for determining third party access prices.

8. Level of security provided in foundation contracts.

Key findings

NERA's report focuses on the regulation of the gas pipeline industry in the US, and in particular, FERC's regulatory role. FERC has regulatory oversight for interstate pipelines and major interstate pipeline developments. This does not appear, in NERA's view, to have hindered the development of the pipeline industry to an extensive network.

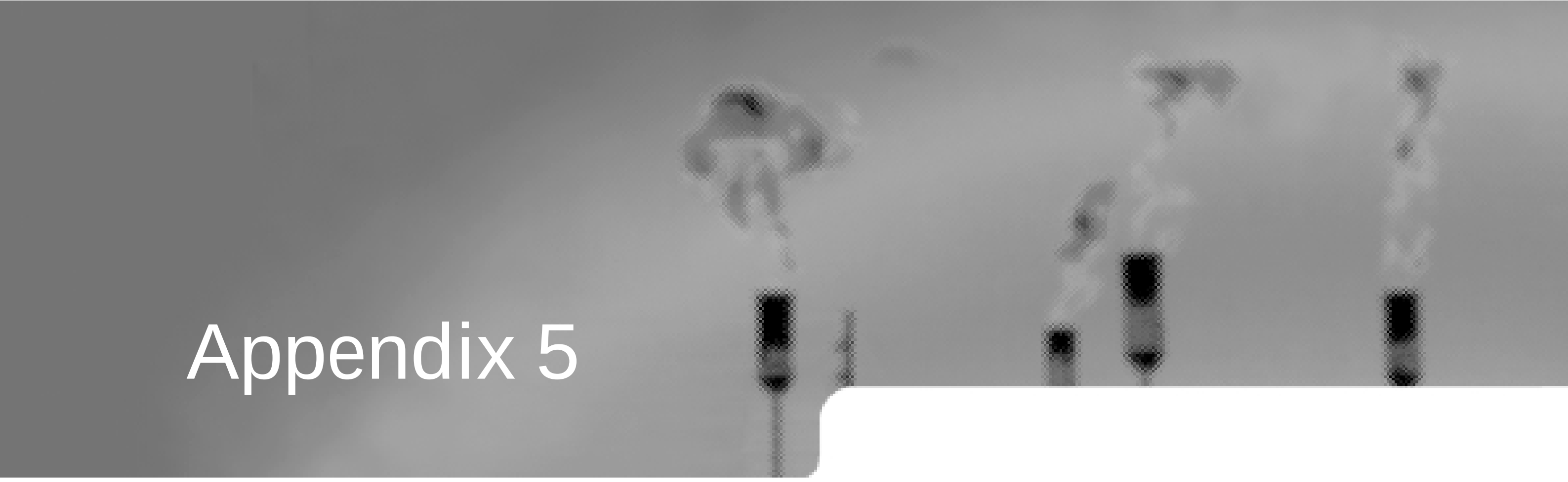
New pipelines and extensions of existing interstate pipelines must obtain a 'certificate of public convenience and necessity' from FERC before being built. NERA considers that the application of an established set of tests in this process provides the industry with certainty.

Long-term contracts for the proposed pipeline projects are an important aspect of the certification process. The contracts underpin the new investment, sharing the long-term investment risks between the pipeliner and the user. The existence of long-term contracts increases the likelihood that the pipeliner's application will be approved and a certificate granted. However, they do not guarantee a certificate.

A feature of US contracts between service providers and users is the inclusion of a fixed charge to recover the investment costs and a variable charge for the marginal costs. NERA notes that as a result of this approach to tariffs there are no formal benefit sharing mechanisms or approaches to deal with blue sky. This contrasts with Australia where volume-based tariffs create the potential for blue sky to occur.

In addition, pipeline contracts in the US do not include most favoured nation' clauses. NERA notes that the inclusion of these clauses in foundation contracts has the effect of limiting the capacity utilisation of the pipeline and, consequently, the market will develop more slowly. The overall efficiency of new pipeline investment is likely to be sub-optimal. In contrast, FERC encourages price discrimination by pipeline service providers with the view to increasing the utilised capacity of the pipeline.

NERA notes that the code appears to be flexible enough to tackle most of the perceived problems associated with new gas pipeline developments in Australia.



Appendix 5

Summary of code provisions that facilitate regulatory certainty

This summary is based on an extract of material from the NERA consultancy, *Natural Gas Pipeline Access Regulation, 31 May 2001*[101]

1. **Section 2, Due process**. Due process is fundamental to regulatory certainty. Section 2 defines the code's provision of due process to the service provider and interested parties. The service provider receives a fair hearing, a decision with reasons, rights of appeal, and a transparent process. Various parties have complained about not being able to examine the actual tariff model of the companies regulated under the code, but NERA feels that there is movement in this direction. These provisions, along with the high level of detail specified in the code, protect the service provider from regulatory caprice.

2. **Section 2.21, Timely regulatory rulings**. Section 2.21 (subject to 2.22) provides that the regulator must issue a final decision within six months of receiving a proposed access arrangement, ensuring that the service provider is not left in limbo indefinitely. Six months is a reasonable length of time, given the long lead times inherent in gas pipeline investments and time needed for consultation and due process. Section 2.43 (subject to 2.44) continues this process for appeals and revisions. Any delays in issuing an access arrangement final decision is likely to be a concern for providers of capital. To mitigate timing uncertainties for regulatory decisions regarding greenfields pipeline projects it is incumbent on project proponents to pro-actively manage regulatory determination processes to ensure regulators are able to promulgate determinations within the minimum prescribed timeframe.

3. **Section 2.24, Protecting interests**. The ACCC, as relevant regulator, is charged with the task of balancing the different interests of parties affected by the services offered on the pipeline, and the terms and conditions on which those services are offered. Accordingly, in assessing an access arrangement the ACCC must consider the interests of the service provider, users, and the public interest. However, it cannot ignore or abrogate the service provider's existing contractual obligations. The factors it must consider are (inter alia):

   (a) the service provider's legitimate business interests and investment in the covered pipeline

   (b) firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline

   (c) the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline

   (d) the economically efficient operation of the covered pipeline.

4. **Section 2.50, Allowance for negotiated arrangements**. Section 2.50 (as well as the preface to section 8) allows for a variety of pricing structures. The code allows pipelines and customers to negotiate any alternative arrangements upon which they both agree. 'The Reference Tariff Principles are designed to provide a high degree of

[101] This summary is based on an extract of material from the NERA consultancy, *Natural Gas Pipeline Access Regulation* (pp. 14–19). 31 May 2001. This summary should not be interpreted as legal advice on the interpretation, effect or scope of the sections quoted. Should further clarification be required readers should seek their own legal advice.

flexibility so that the Reference Tariff Policy can be designed to meet the specific needs of each pipeline system.'[102] However, coverage under the code is meant to limit the exercise of pipeline monopoly power, by capping pipelines' charges at their efficient costs, in aggregate. Pipelines have great latitude in price setting, subject to this restriction.

5. **Section 3.16(b), Pricing expansions**. Section 3.16(b) sets out the pricing policy for future investments in expansions/ extensions (subject to 8.25 and 8.26, discussed below). Thus, when making commercial decisions the service provider and its users can know how any prospective future investments will be priced.

6. **Sections 3.18 and 3.19, Access arrangement duration**. Sections 3.18 and 3.19 allow for an access arrangement duration of any period. While five years is the default expectation, it is explicitly **not** required. Where an access arrangement period is longer than five years, the regulator must consider whether mechanisms should be included to address the risks of forecasts proving incorrect. A new pipeline seeking a longer duration (e.g. 10 years) could receive one under the code's provisions, provided it can satisfactorily support its request. A longer initial access arrangement period may be desirable to the service provider, as it can provide greater certainty for a longer period of time over the price path the company will use for its regulated services.

7. **Section 6, Foundation shippers**. The preface to section 6 recognises the importance of contractual rights, including contracts held by 'foundation shippers.'[103] The code enables these arrangements to proceed without interference.

8. **Section 6, Dispute resolution**. Section 6 of the code sets out a formal dispute resolution mechanism. It provides the pipeline with the confidence that disputes will be adjudicated in a predetermined process. The code lays out guidelines, restrictions, and a formal procedure for the dispute arbitrator, protecting the pipeline from arbitrary, capricious, or confiscatory decisions.

9. **Section 6.15, Guidance for the arbitrator.** Section 6.15 of the code requires that the disputes arbitrator must take into account (inter alia):

   (a) the service provider's legitimate business interests and investment in the covered pipeline

   (e) firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline

   (f) the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline

   (g) the economically efficient operation of the covered pipeline.

   Under Section 6.15, the arbitrator must also take into account 'the costs to the service provider of providing access.'

10. **Section 6.18, Restrictions on decisions.** Section 6.18 limits the type of decisions an arbitrator can make, including decisions which that impede the rights of existing users to obtain services, and any decision which that requires the service provider to provide services or any tariff other than a reference tariff.

11. **Section 8, Reference tariffs**. Section 8 specifies the method for setting prices, the costs that will be examined and how they will be examined, and a formal process for doing so. These tariff principles give a company's investors considerable certainty regarding their return on investment. While not **guaranteeing** revenues, the tariff principles ensure that the company has a fair opportunity to earn them.

[102] Section 2.50 states: 'For the avoidance of doubt, nothing (except for the Queuing Policy) contained in an access arrangement (including the description of services in a services policy) limits: (a) the services a service provider can agree to provide to a user or prospective user; (b) the services that can be the subject of a dispute under section 6; (c) the terms and conditions a service provider can agree with a user or prospective user; or (d) the terms and conditions that can be the subject of a dispute under section 6.'

[103] 'Because the arbitrator cannot deprive a person of a contractual right, 'foundation shippers' contracts cannot be overturned by the arbitrator at either the service provider's or foundation shipper's request.'

12. **Section 8.3, Form of regulation**. Section 8.3 allows the service provider two alternatives for setting prices: a 'price path' or 'cost of service.' The price path approach assures the company of the prices it can charge for the duration of the access arrangement (which could be greater than five years). The cost of service approach adjusts the company's prices 'continuously in light of actual outcomes … to ensure that the tariff recovers the actual costs of providing the service.' The pipeline decides which alternative to propose; thus, it can select whichever one it deems fits its best interests. A service provider wanting a 'hands off' regulatory arrangement can request it while a company wanting greater certainty of cost recovery can request that instead.

13. **Section 8.4, Total revenue**. Section 8.4 provides three alternative methodologies for calculating the revenue target. Like section 8.3, this section offers the certainty of a cost-of-service-based revenue target methodology, including a return on the asset value and an allowance for inflation (section 8.5). The alternative methodologies—internal rate of return and net present value—are meant to provide the same result. From the total revenue determination, reference tariffs are calculated to provide that revenues match costs.

14. **Section 8.12, Initial capital base, New pipelines.** Section 8.12 states that the initial capital base will be valued by the actual costs of the asset and that these costs will be used to set reference tariffs (Section 8.8). These provisions protect the service provider from the sorts of downward revaluations that could result from the application of hypothetical or theoretical asset valuation methodologies. At the same time they protect customers from the exercise of market power by a pipeline. Still, pipelines and their customers are free to negotiate other prices, and foundation customer contracts remain protected. The side-by-side existence of these provisions—cost-based prices and the freedom to negotiate—provides pipeline companies and their customers with a combination of regulatory and commercial freedom.

15. **Section 8.14, Rolling the asset base forward**. Section 8.14 builds on section 8.12, determining the means by which the asset base will be valued at the expiry of one access arrangement period and the commencement of a subsequent one. Section 8.14 states that the rolled-forward asset base will be:

    > … the Capital Base applying at the expiry of the previous Access Arrangement adjusted to account for the New Facilities Investment or the Recoverable Portion (whichever is relevant), Depreciation and Redundant Capital (as described in section 8.9) as if the previous Access Arrangement had remained in force.

    In other words, when establishing a new access arrangement, the regulator cannot apply an alternative methodology that would decrease (or increase) the asset value.

16. **Section 8.16, Pricing capacity expansions**. Section 8.16, along with sections 8.25 and 8.26, allows for expansion capacity to be priced at either: (1) the price level of existing capacity, without necessitating a review of access arrangements; or (2) a surcharge to both existing customers and new ones, where benefits accrue sufficiently to existing customers. Allowing for expansions to be priced at the existing price level can provide regulatory certainty to pipelines regarding the price level. Similarly, a predefined set of rules for increasing reference tariffs at expansions provides certainty about how investment cost recovery will take place.

17. **Section 8.19, Speculative investment**. Section 8.19 of the code deals with pipeline investments over and above the amount of investment in new facilities that would go into the capital base. This section allows for the creation of a speculative investment fund that can later be put into the capital base when these assets are called for. Until that time the capital invested is held in this account and can accrue a rate of return on that investment, which will also be collected when the investment amount is put into the capital base. This regulatory 'hold account' is a flexible, powerful provision. A service provider that anticipates future increases in demand beyond current amounts can make

a large investment all at once—taking advantage of scale and scope economies—without the excess amount of its investment being declared imprudent and written down. This is an important provision for providing investors with regulatory certainty. At the same time it protects existing customers from paying the costs of spare capacity.

18. **Sections 8.30 and 8.31, Rate of return**. Sections 8.30 and 8.31 of the code set out the mechanism by which pipeline investors recover the costs **on** an investment—i.e. the rate of return on regulated pipeline investments—specifying clearly that the methodology used:

> should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service. (Section 8.30)

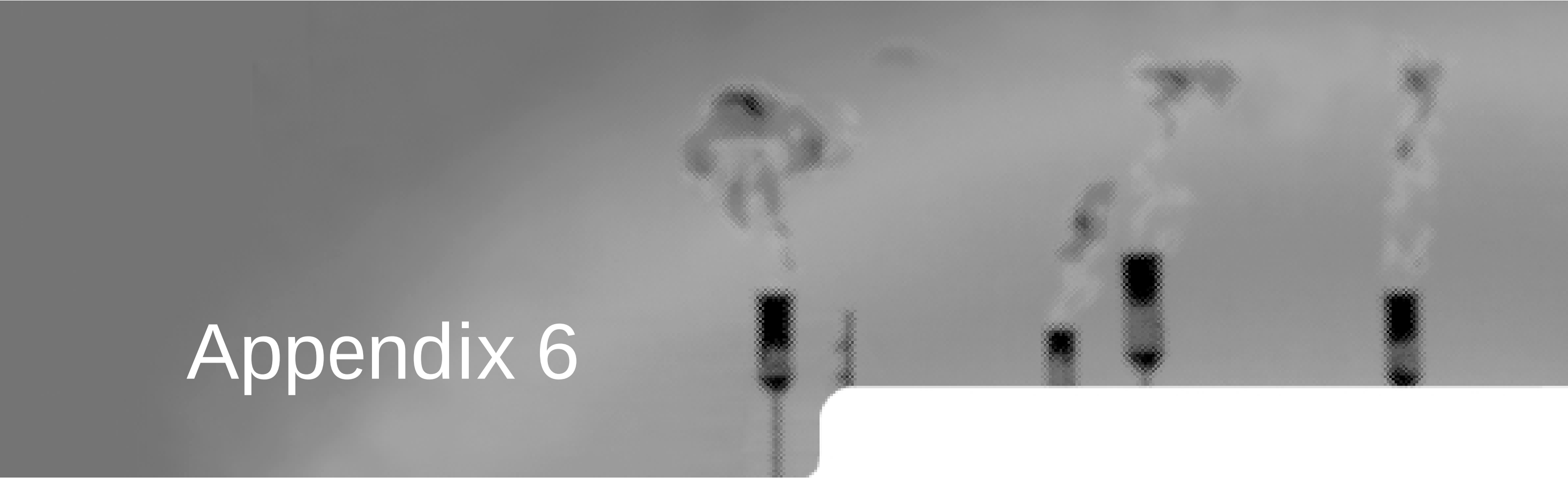
Section 8.31 specifies, via an example, how this can be carried out to satisfy the code's requirements. Specifying the rate of return methodology provides an important degree of regulatory certainty to investors by ensuring that they will not be subject to regulatory hold-up through either an outright denial of a return on their investment, or of a methodology that fails to reflect the risks inherent in the business—a universal concern of pipeline investors. The ACCC/ORG cost of capital forum (3 July 1998) produced considerable valuable evidence on cost of capital procedures. The conclusions from that forum have been referenced in many subsequent regulatory decisions in Australia, and they provide a reliable basis for calculating the cost of capital in the future.

19. **Section 8.32 and 8.33, Depreciation**. Section 8.32, on depreciation, sets out rules for the mechanism by which pipeline investors recover the costs **of** an investment. Depreciation methodologies are another means by which investors' money can be put at risk by a bad regulatory regime. The failure to specify a depreciation practice, or to specify one that is vague or subjective, can result in regulatory expropriation of investors' funds. The code addresses these concerns head-on by specifying that a regulated asset is fully depreciated once, and only once, over its economic life. In this way the code strikes a balance in which investors recover the costs of their investments, and customers are protected form the exercise of monopoly power.

20. **Section 8.43, Discount practices**. Section 8.43 of the code allows, under certain specified conditions, for the service provider to extend discounts to price-sensitive customers, and recover the otherwise foregone revenues from its other customers. This provision of the code provides a means by which efficient usage of the pipeline can be furthered—through avoiding having a pipeline sit with idle capacity—while not leaving the pipeline with a revenue shortfall. In sum, even after discounting to price-sensitive customers who would otherwise not take pipeline service, target revenues continue to match the pipelines' costs.

21. **Sections 8.47 and 8.48, Fixed principles**. Sections 8.47 and 8.48 deal with fixed principles. These provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods. In this way a service provider seeking certain provisions to be sustained over a long term can do so without necessarily having to propose a very long access arrangement duration.

Structural elements specifically include 'the depreciation schedule, the financing structure, and that part of the rate of return that exceeds the return that could be earned on an asset that does not bear any market risk.' These provisions can provide investors with long-term regulatory certainty over how their investment will be treated. The provisions clarify parameters over which the regulator might otherwise seek to exercise discretion and which could leave investors unclear about future regulatory changes.



Appendix 6

Glossary

ACCC	Australian Competition and Consumer Commission
access arrangement	Arrangement for third party access to a pipeline provided by a pipeline owner and/or operator and submitted to the relevant regulator for approval in accordance with the code
access arrangement information	Information provided by a service provider to the relevant regulator pursuant to section 2 of the code
access arrangement period	The period from when an access arrangement or revisions to an access arrangement takes effect (by virtue of a decision pursuant to section 2) until the next revisions commencement date
the Act	*Gas Pipelines Access (South Australia) Act 1997*
AGA	Australian Gas Association
bare transfer	When the terms of a contract with a service provider are not altered as a result of transfer or assignment of capacity rights
CAPM	Capital asset pricing model
COAG	Council of Australian Governments
code	*National Third Party Access Code for Natural Gas Pipeline Systems*
covered pipeline	Pipeline to which the provisions of the code apply
CPI	Consumer price index
CPI-X	An adjustment that provides an automatic mechanism for adjusting tariffs to take account of ongoing inflation and provides for the corresponding changes in rates of return observed in commercial markets
CWP	Central West Pipeline
derogation	A legislative exemption from compliance with specified obligations set out in the code
Duke	Duke Energy International

EGP	Eastern Gas Pipeline
Energy Users	Energy Users Association of Australia
E_D	Expected demand
FERC	Federal Energy Regulatory Commission
gas code	*National Third Party Access Code for Natural Gas Pipeline Systems*
GJ	GigaJoule
greenfields pipeline	For the purposes of this guideline, a greenfields pipeline is considered to encompass both proposed pipelines and new pipelines, the market for the output of which was previously non-existent
guideline	*Greenfields guideline for natural gas transmission pipelines*
ICB	Initial capital base
MFN	Most favoured nation
Mpa	Megapascal (unit of pressure)
NCC	National Competition Council
NERA	National Economic Research Associates
NPV	Net present value
OffGAR	The Office of Gas Access Regulation, Western Australia
Part IIIA	Part IIIA of the *Trade Practices Act 1974*
PCCM	Project cost containment mechanism
PJ	PetaJoule (equal to 1 000 000 GJ)
PTRM	Post tax revenue model
queuing policy	A policy for determining the priority that a user, or prospective user has, as against any other user, or prospective user, to obtain access to spare capacity
reference service	A service that is specified in an access arrangement and in respect of which a reference tariff has been specified in that access arrangement
reference tariff	A tariff specified in an access arrangement as corresponding to a reference service and which has the operation that is described in sections 6.13 and 6.18 of the code
ROE	Return on equity

reference tariff policy	A policy describing the principles that are to be used to determine a reference tariff
revisions commencement date	The date upon which the next revisions to the access arrangement are intended to commence
revisions submissions date	The date upon which the service provider must submit revisions to the access arrangement
service	A service provided by means of a covered pipeline including: (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul) (b) the right to interconnect with a covered pipeline (c) services ancillary to the provisions of such services but does not include the production, sale or purchasing of natural gas
service policy	A policy detailing the service or services to be offered.
service provider	The person who is the owner or operator of the whole or any part of the pipeline or proposed pipeline
shipper	An alternative term generally used in this guideline to describe an existing user of the pipeline
SFV	Straight fixed variable
TJ	Terajoule (equal to 1 000 GJ)
TPA	*Trade Practices Act 1974*
Vanilla WACC	The nominal weighted average of the cost of equity and debt to the business before any adjustments for taxes and change in the general level of prices Vanilla WACC = $E/V.R_e + D/V.R_d$ Where R_e is the post-tax cost of equity determined by the CAPM formula and R_d is the pre-tax nominal cost of debt.
WACC	Weighted average cost of capital

Appendix 7

Related publications

ACCC, *Access regime—a guide to Part IIIA of the Trade Practices Act*, November 1995.

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Davis, K and Handley, J, Report on *Cost of capital for greenfields investment pipelines*, February 2002.

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Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No. 1,* May 2001.

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